BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
LC 48

In the Matter of Portland General Electric 2009 Integrated Resource Plan.	STAFF'S FINAL COMMENTS AND RECOMMENDATIONS

The following are Staff's final comments and recommendations on Portland General Electric Company's (PGE) 2009 Integrated Resource Plan (IRP or the Plan). In these Final Comments Staff discusses its analysis of and conclusions regarding the IRP and addresses concerns raised by multiple intervenors and interested parties. In Appendix A to these comments, Staff discusses each of the Commission's IRP Guidelines and Staff's conclusions regarding PGE's compliance with them.

Staff's recommends that the Commission acknowledge PGE's 2009 IRP with the understanding that PGE will meet the following requirements, in the timeframe described by staff. Staff explains the reasons underlying these recommended requirements in the discussion below.

1. *In the event the EQC denies PGE's request to amend its Regional Haze Plan to facilitate PGE's BART III proposal, PGE must include in its next IRP Update an alternative preferred proposal and supporting analysis.*

2. *PGE will include in its next IRP Update:*

    a. *An updated plan of service and project calendar or Cascade Crossing;*

    b. *Status of equity and capacity participation and interconnection agreements;*

    c. *Status of directional ratings on all circuits proposed;*

    d. *The same benefit-cost model PGE used in its IRP updated to contain then current inputs for Cascade Crossing and continued transmission service from BPA.*

3. *PGE will include in its next IRP:*

    a. *An evaluation of potential transmission reinforcement between Salem and Oregon City areas with alternative northern endpoints, with and without equity partners.*

    b. *Sensitivity analysis around financial and factual assumptions underlying transmission decisions in future IRPs.*

4. *PGE must update its load forecast in PGE's next IRP Update.*

5. *In the next planning cycle, PGE must analyze the extent of potential load loss due to distributed and self generation.*

6. *In its next IRP Update, PGE must meet Guideline 7 in its entirety, and therefore must provide the following information to allow comparison of DR on par with other options for meeting energy, capacity, and transmission needs:*

   a. *MW projections of capacity "contributions" by year and by DR class (e.g., Class 1 is directly dispatchable load curtailment; Class 2 DR relates to dynamic price signals and customer responsiveness thereto); and*

   b. *Projected cost per MW of capacity savings by DR type.*

7. *In its next IRP Update and in the next planning cycle, PGE must evaluate the potential for Conservation Voltage Reduction*.

8. *In its next IRP Update and in the next planning cycle, PGE must evaluate the use of unbundled RECs in its strategy to meet RPS Requirements for the entire planning period.*

9. *In its next IRP Update and in the next planning cycle, PGE must evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.*

10. *In its next IRP Update and in the next IRP planning cycle, PGE must include a wind integration study that has been vetted by regional stakeholders.*

11. *In its next IRP Update and all subsequent IRPs, PGE must comply with all requirements of Guideline 11.*

Boardman

Recommended requirement:

> *In the event the EQC denies PGE's request to amend its Regional Haze Plan to facilitate PGE's BART III proposal, PGE must include in its next IRP Update an alternative preferred proposal and supporting analysis.*

PGE requests that the Commission acknowledge its BART III proposal for compliance with the Oregon Regional Haze Plan and Oregon Utility Mercury Rule standards. PGE argues that the compliance actions in its BART III proposal are the least cost and least risk options for ratepayers. PGE believes these actions define a reasonable transition to non-coal fuel resources and would set national precedent.

PGE concedes that its BART III proposal does not guarantee that future regulation of hazardous air pollutants or the resolution of pending litigation in United States District Court will not require PGE to install additional controls at Boardman prior to 2020. PGE asks the Commission to acknowledge its BART III compliance actions despite these risks. In the event that the EQC fails to approve BART III, PGE requests acknowledgement of full implementation of BART I controls and continued operation of the Boardman plant through a least 2040. Based on incremental rate impact analysis, PGE concludes that the BART I emission controls, as modeled in the Diversified Thermal with Green portfolio, outperform the other shutdown options and is the second best option for ratepayers.[1]

PGE argues that backstop acknowledgment is necessary because any delay in ordering the equipment needed to implement BART I will subject ratepayers to increased costs and risks and could result in a potential temporary shut-down of the Boardman plant or failure to meet the BART I emissions standards.

Staff recommends that the Commission acknowledge PGE's BART III proposal. Staff recommends that the Commission not acknowledge PGE's BART I backstop proposal, but instead require PGE to include a backstop proposal and supporting analysis in its next IRP Update if EQC denies its request to revise the Regional Haze Program to facilitate PGE's BART III proposal.

Staff primarily focused its analysis of PGE's portfolio modeling on three metrics, expected cost, the average of the four worst deterministic futures, and the stochastic TailVar90 risk metric. Staff also reviewed the analysis and comments of the other parties in this case. Based on this analysis, Staff agrees with PGE that its BART III proposal represents the portfolio with the best combination of cost and risk for ratepayers. The BART I portfolios, including Diversified Thermal with Green, would impose too great of a risk on ratepayers from future federal and state regulation of carbon emissions. Staff also agrees with PGE that the execution risks associated with implementing the earlier shutdown scenarios are also significant.

While Staff agrees with the Northwest and Intermountain Power Producers Coalition (NIPPC) and Northwest Independent Energy Coalition (NWEC) that power purchases from independent power producers or the wholesale power market could be used to bridge the early energy and capacity deficits associated with these scenarios, Staff concludes that the risk associated with this type of strategy is not in the best interest of ratepayers. For these reasons, Staff recommends that the Commission acknowledge PGE's BART III proposal.

The Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, and the Northwest Environmental Defense Center (hereinafter "the Coalition"), NWEC, and Ecumenical Minstries of Oregon (EMO) claim that PGE has overstated its energy and capacity needs related to Boardman shutdown. While Staff agrees that there is evidence that PGE's reference case load forecast may overstate future demand, our analysis indicates that PGE's energy and capacity need remains significant even under a lower load scenario. Under PGE's reference case load forecast, with Boardman operating, PGE is short 952 annual average megawatts (MWa) of energy in 2016 (See: PGE Response to Staff Data Request No. 75). Shutting down Boardman in late 2015 would push that deficit to 1,266 MWa in 2016. Updating PGE's model to include its

[1] PGE's August 10, 2010 Comments at p. 15.

low load scenario, with Boardman shutdown in 2015, the resource deficit would be 1,158 MWa in 2016. The winter and summer capacity deficits under this low load scenario without Boardman are 1,979 MW and 1,788 MW, respectively. These resource gaps are significant and would be challenging to fill if Boardman were shut down in 2016.

Staff also agrees with the Coalition and NWEC that PGE's reference case natural gas price is slightly overstated. However, PGE's response to the Commission's bench request, which tested a combined low natural gas price, low load forecast scenario, continues to show very little difference between the shutdown scenarios on an expected cost basis. Staff prefers PGE's BART III proposal because it allows adequate time to implement a lower-risk replacement resource strategy.

Regarding acknowledgement of a backstop option, Staff favors Boardman shutdown options with low execution risk. PGE has steadfastly argued that any replacement resource needs to be another baseload resource. Staff notes replacement with a natural gas CCCT is also likely to be the option with the lowest execution risk. Furthermore, PGE's IRP modeling also indicates that replacement with natural gas is more cost-effective than replacement with a mix of renewable resources. Staff recommends that the Commission require PGE to address any needed fallback options in and IRP Update.

Cascade Crossing

Recommended requirements:

PGE will include in its next IRP Update:

- *a. An updated plan of service and project calendar or Cascade Crossing;*
- *b. Status of equity and capacity participation and interconnection agreements;*
- *c. Status of directional ratings on all circuits proposed;*
- *d. The same benefit-cost model PGE used in its IRP, updated to contain then current inputs for Cascade Crossing and continued transmission service from BPA.*

PGE will include in its next IRP:

- *a. An evaluation of potential transmission reinforcement between Salem and Oregon City areas with alternative northern endpoints, with and without equity partners.*
- *b. Sensitivity analysis around financial and factual assumptions underlying transmission decisions in future IRPs.*

PGE states that its request for acknowledgement of the Cascade Crossing Transmission Project ("Cascade Crossing") depends on whether this transmission project makes economic sense from the ratepayer perspective. PGE states that its decision to advance Cascade Crossing is based on analysis of the project including the estimated path rating for the line, detailed construction cost estimates, the level of equity participation, the number of transmission service requests received by PGE and the generation facilities that would utilize the line.[2]

In response to data requests, PGE provided staff with a benefit-cost analysis model that evaluates the net present value of building the line compared to continued service through the Bonneville Power Administration (BPA). The model includes the capability to perform sensitivity analysis, including the identification of tipping points where the economics of the project change. One important input is third-party equity participation in the project. A recent Memorandum of Understanding (MOU) between PacifiCorp and PGE indicates the PacifiCorp may become an equity partner by the end of this year. Equity participation is a key variable that can tip the economics of the project to being beneficial for PGE's ratepayers.

PGE's analysis indicates that the estimated capacity, by 2015, on the proposed Cascade Crossing transmission project, exceeds what could be delivered on a single 500 kV circuit line. PGE's projected path ratings also support the configuration of a double circuit line with PacifiCorp's potential equity participation.

Staff's recommendation tracks with PGE's proposal to base its decision whether to proceed with Cascade Crossing on future economic analysis. Staff recommends that the Commission acknowledge PGE's proposal to build Cascade Crossing as specified in Action Item 16, subject to the requirement that PGE include information in its IRP Update that will allow stakeholders and the Commission to make informed decisions regarding the economic benefit of Cascade Crossing.

<u>Intervenor Comments</u>**:** CUB identified concerns regarding Cascade Crossing, but did not recommend against acknowledgment. More specifically, CUB wonders why the expected closure of Boardman does not affect Cascade Crossing, whether BPA can provide sufficient transmission to obviate the need for Cascade Crossing, whether PGE's inexperience will result in cost overruns, and whether it is appropriate to spend on transmission when other investments are already in the queue.[3] Willard Rural Association ("WRA") asks the Commission not to acknowledge Cascade Crossing, arguing:

- Energy consumption in the past twelve years and projections regarding energy consumption in the future indicate "there is no present need to build a large power line into Salem."

- "PGE's own cost-benefit analysis in the IRP indicates that a self-build is a bad deal for Oregon ratepayers in 60% of PGE's scenarios and close to break-even in the other 40% if all of PGE's assumptions are accepted."

---

[2] IRP at 326-27.

[3] CUB Comments at 2.

- PGE has not included cost of upgrades to other transmission facilities in the Willamette Valley necessitated by Cascade Crossing.
- PGE has underestimated the cost to acquire right-of-way
- PGE has overestimated the amount of wind generation to come on-line in eastern Oregon and underestimated the capacity that will be available to transmit wind generation

While WRA's comments touch on issues that are integral to PGE's resource decisions, it appears that WRA fails to comprehend certain complexities of integrated resource planning and thus, WRA's comments are not persuasive. For example, WRA argues that because PGE's load does not appear to be growing there is no need for a new transmission line to PGE's service territory.

However, under the Commission's IRP guidelines, whether to add transmission resources is a decision that the utility must base on multiple considerations, not just expected load. WRA also argues that the majority of PGE's own analysis shows that it is less expensive to use BPA transmission than to build Cascade Crossing. Under Guideline 1, the primary goal is a selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. WRA has focused on cost and discounted the risk of relying on third-party transmission to serve future transmission needs.

CUB's comments raise concerns similar to those that Staff had or that Staff also investigated. Staff's review of PGE's IRP reflects that PGE's analysis underlying its Cascade Crossing proposal is consistent with the Commission's IRP guidelines. Staff's independent review of PGE's analysis and of the guidelines supports PGE's request for acknowledgment of Cascade Crossing, subject to the requirements noted above. These requirements should address several of CUB's concerns.

Discussion**:** Guideline 5 specifies that utilities are to treat transmission facilities as resource options and when considering whether to include them in the resource plan, take into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability. PGE's IRP reflects that PGE's analysis is compliant with this guideline. Staff's independent review reflects that the considerations of Guideline 5 support PGE's conclusion that it should acquire additional transmission capability.

A. Additional purchases and sales. WECC TEPPC Historical Analysis Work Group's 2010 Path Utilization Study[4] indicates lines similar to the Cascade Crossing have substantial opportunity for spot sales. Benefit grows with each new transmission line interconnected near Boardman. The potential that Cascade Crossing will facilitate market sales and purchases is high.

[4] Western Electricity Coordinating Council, Transmission Expansion Planning Policy Committee 2010 Western Interconnection Transmission Path Utilization Study released May 7, 2010

B. Access less costly resources in remote locations. Additional transfer capacity across the Cascades improves PGE's access to resources in eastern Oregon, and potentially to resources owned by third parties in Idaho and Montana.

C. Alternative fuel supplies. Additional transfer capacity across the Cascades improves PGE's access to wind generation facilities that are concentrated in the eastern part of the state. This spring the US Department of Energy (DOE) expressed concern that "there is a growing problem with congestion in the Columbia River Gorge where there is more wind generation planned in eastern Washington and Oregon than the existing transmission system to the west can accommodate." In addition, the North American Electric Reliability Corporation (NERC) notes that the integration of high levels of variable generation requires new transmission to access ancillary services necessary to manage variable power output. Cascade Crossing addresses these concerns.

D. Reliability. In an electrical emergency, Cascade Crossing will provide PGE access to many alternative sources of market energy. Cascade Crossing will increase NW grid flexibility and the ability to withstand sudden disturbances, such as short circuits.

Staff concludes that the Guideline 5 factors support PGE's proposal to acquire additional transmission capability.

Guideline 1 requires utilities to evaluate resources on a consistent and comparable basis and to evaluate risk and uncertainty**.** PGE compared the cost of building Cascade Crossing to the cost of acquiring transmission service from BPA Transmission ("BPAT"). PGE analyzed the "economic benefit" of Cascade Crossing, (defined as the cost of utilizing BPA transmission service minus the cost of Cascade Crossing), for the IRP's top three preferred scenarios against five cases. The five cases utilize different assumptions for the growth rate of the BPA transmission tariff rate and the extent to which PGE may partner with other entities to build the project.

PGE's analysis shows that Cascade Crossing is economic with relatively conservative estimates regarding BPA transmission rate increases, equity participation by third parties, and requests for service by third parties. Notably, PGE's projections of BPA's future transmission capacity and costs are very conservative. PGE assumes that in the absence of Cascade Crossing, BPA would construct new transmission that would enable PGE to transmit power from PGE's existing and proposed resources to its service territory. PGE further assumes that it would pay for BPA transmission service at BPA's embedded tariff rates. However, it is PGE's understanding that BPA does not currently plan to build such facilities and that even if it did; it is unlikely charges for service on these facilities would be at embedded rates.

Uncertainty regarding the operating life of Boardman does not have significant impact on Staff's recommendations regarding Cascade Crossing because:

- The convergence of transmission lines and gas pipelines near Boardman makes continued alternate utility or independent power generation a distinct possibility.
- Full or partial replacement of Boardman with wind resources would likely require transmission for the full nameplate capacity of the wind to secure financing for the projects.

- Replacement options that rely on market purchases would likely be facilitated by direct transmission to eastern Oregon.

Finally, Staff recommends that the Commission impose two requirements for PGE's next IRP. First, Staff recommends that the Commission require PGE to include certain analysis in PGE's next IRP. PGE's IRP did not include sufficient sensitivity analysis. PGE provided the analysis in response to Staff data requests and will provide additional analysis in its IRP Update. However, Staff recommends that the Commission clarify that such analysis is integral to integrated resource planning and require PGE to include it in all future IRPs.

Second, Staff recommends that the Commission require PGE to provide an evaluation of potential transmission reinforcement between Salem and Oregon City areas with alternative northern endpoints, with and without equity partners. PGE did include the potential costs of the Willamette Valley Upgrades in the estimated costs of Cascade Crossing. However, PGE does not ask for acknowledgment of these upgrades because PGE is not sure yet whether they will be needed.[5] Staff recommends that the Commission require PGE to provide an analysis of the need for and cost of the upgrades in PGE's next IRP.

Load forecast

Recommended requirements:

PGE must update its load forecast in PGE's next IRP Update.

In the next planning cycle, PGE must analyze the extent of potential load loss due to distributed and self generation.

The range of load forecasts in PGE's IRP provides a reasonable basis for PGE's portfolio selection. However, Staff recommends that the Commission direct PGE to update its forecasts in its next IRP Update to facilitate the analysis of whether PGE's resource acquisition plans should be scaled up or back.

Staff agrees with the comments filed by the NW Energy Coalition (NWEC), Ecumenical Ministries of Oregon, (EMO) and other intervenors that PGE failed to provide a believable explanation of PGE's expected rate of growth of higher than 1.7% a year during 2010-15. This flaw does not alter Staff's conclusions regarding PGE's portfolio selection. Nonetheless, for the reason stated above, Staff recommends that PGE include a new load forecast in its next IRP Update.

The National Bureau of Economic Research announced in September that business activity "troughed" in June 2009, marking the end of the last national recession. Historically, Oregon has recovered from recessions faster than average, but this has not been true for the last two recessions. One year after the June 2009 trough, Oregon's unemployment rate is at 10.6% and increased job losses are projected through the 3rd calendar quarter. The nation's previous

---

[5] PGE IRP at 22-23.

recession (in 2001) lasted approximately eight months nationally and lasted approximately 31 months in Oregon. Oregon's unemployment peaked at 8.5% and was above 7% for 37 months.

Staff agrees with comments of interveners that there are no signs that Oregon's economy will rebound quickly from the 2007-09 recession. Jobs growth has been slowing for the whole country since 2006, and we have not overcome this trend. The Global Insight September utility forecast predicts that Oregon utilities will reach the 2007 production level by second quarter of 2013.

Demand (load) forecasting is a difficult area even in a stable economy under sustaining (traditional) technologies. It becomes especially difficult when the economy is uncertain and the industry is facing "disruptive" technology of distributed generation and energy efficiency and "supportive" technology of electric vehicles.

Staff believes that PGE's projected load growth rate does not adequately account for the continued effects of the 2007-09 recession. Staff thinks that the annual rate of growth for years 2010-15 for the medium case scenario will not reach the 1.7% estimated by PGE. However, Staff does not think PGE's load growth forecast is overstated to the degree suggested by NWEC.

NWEC relies on energy growth forecasts in the Northwest Power and Conservation Council (NWPCC) Sixth Regional Power Plan to assert that PGE's projected load is such that there is no need to operate Boardman past 2015. (May 14, 2010 NWEC Comments at 6.) If NWPCC's conservation goals are met, NWPCC predicts 0.3% growth in electric load in Oregon and a decline in residential sector load of 0.7%. Under a scenario of frozen efficiency NWPCC predicts growth in the range of 0.8 to 1.8%, with the reference case 1.2% a year for the period of 2010-2030.

Replacing PGE's 1.7% load growth forecast with the NPCC's 1.2% reference case forecast would result in an approximate 128 MWa reduction to PGE's forecasted load for 2015. This reduction is consistent with moving from PGE's reference case forecast to PGE's low load forecast. Staff used PGE's low load forecast to evaluate PGE's energy and capacity needs both with and without Boardman.

Demand Response:

Recommended requirement:

> *In its next IRP Update, PGE must meet Guideline 7 in its entirety, and therefore must provide the following information to allow comparison of DR on par with other options for meeting energy, capacity, and transmission needs:*
>
> a. *MW projections of capacity "contributions" by year and by DR class (e.g., Class 1 is directly dispatchable load curtailment; Class 2 DR relates to dynamic price signals and customer responsiveness thereto); and*

b. Projected cost per MW of capacity savings by DR type.

Guideline 7 specifies that "[p]lans should evaluate demand response resources, including voluntary programs, on par with other options for meeting energy, capacity, and transmission needs." The Company did not comply with this guideline because PGE did not provide information showing an evaluation of DR on par with other resource options.

PGE's IRP includes the following re: DR:

- A cursory cataloging of DR, or DR "opportunities" by customer category and DR type (e.g., direct load control, critical peak pricing).
- Quantitative projections over time, and developed in conjunction with The Brattle Group, of the MW *potentials*, in the aggregate, for reducing PGE's winter and summer peak loads based on the deployment of various enabling technologies.
- The qualitative nature of various DR options (e.g., from appliance controls to real-time pricing) and PGE's involvement in their development and implementation, and, in some instances, a rough estimate of their potential capacity reduction benefits (in MWs).
- A definitive projection of 50 MW of firm "DR-RFP," and 10 MW of curtailable load reduction (Schedule 77) by large industrial customers.

    - Not explained explicitly was why, for years 2012-2016 (*see* page 224 and Table 4-9 on page 68), the 50 MWs plus 10 MWs were the *only* DR benefits that were projected.

The information listed above does not reflect that PGE considered DR "on par with other options for meeting energy, capacity, and transmission needs." Staff believes the following information should be included for this purpose.

- MW projections of capacity "contributions" by year and by DR class (e.g., Class 1 is directly dispatchable load curtailment; Class 2 DR relates to dynamic price signals and customer responsiveness thereto).
- Projected cost per MW of capacity savings by DR type.

Energy Efficiency

Recommended Requirement:

> *In its next IRP Update and in the next planning cycle, PGE must evaluate the potential for Conservation Voltage Reduction.*

Guideline 6 imposes four requirements. First, each utility must ensure that a conservation potential study is conducted periodically. Second, to the extent the utility controls the level of funding for conservation programs in its service territory, the utility must include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs. To the extent a third party administers conservation programs, the utility must (1) determine the amount of conservation resources in the best cost/risk portfolio without any limits on funding, and (2) identify the preferred portfolio and action plan consistent with the third-party's projection of conservation acquisition.

PGE complied with three of the four requirements in Guideline 6. The Energy Trust of Oregon (ETO) assessed PGE's potential for energy efficiency acquisition.[6] Most of the technical potential for energy efficiency identified by the ETO must be acquired through programs administered by the ETO. PGE includes the analysis required by Guideline 6 for conservation programs administered by third parties.

The ETO identified the technical potential for 19 MWa of efficiency from conservation voltage reduction, which is not an efficiency measure administered by the ETO. Instead, conservation voltage reduction is an efficiency measure the utility itself applies in its distribution system.[7] PGE's IRP includes no analysis reflecting that it considered conservation voltage reduction as a resource or evaluated whether it should be included in PGE's action plan.

RPS Requirements

Recommended requirements:

> *In its next IRP Update and in the next planning cycle, PGE must evaluate the use of unbundled RECs in its strategy to meet RPS Requirements for the entire planning period.*
>
> *In its next IRP Update and in the next planning cycle, PGE must evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.*

PGE's Resource Action plan includes putting an additional 122 MWa of renewable resources in service by the end of 2014. To accomplish this goal PGE intends to "consider all forms of renewables with bundled Renewable Energy Credits (REC) that are Oregon Renewable Portfolio Standard (RPS) compliant."[8] In its IRP, PGE focused on being in "physical" compliance with the 15 percent RPS Requirement for 2015-2019 and accordingly, did not consider using unbundled RECs to meet the RPS Requirement for these years.

[6] PGE IRP at 56.

[7] PGE IRP at 56, Table 4-1.

[8] *See* PGE IRP at 323.

Figure 6-3 shows that PGE's projected REC cumulative bank balance, without the addition of 122 MWa of new renewable resources, does not encounter a shortfall until 2020.[9] As noted above, Staff believes that PGE has over-forecasted its load. Accordingly, it is likely that PGE will be in compliance with the RPS beyond 2020 without the addition of the 122 MWa of renewable resources in 2014. Furthermore, PGE does not discuss, or take into consideration, the REC contributions of its action items associated with Biomass, Geothermal, and Solar PV.

Physical compliance with the RPS is not a requirement of the law. Senate Bill 838's mandated use of banked RECs allows the utility to invest over time to mitigate potential rate impacts to ratepayers that may have occurred if physical compliance was required. PGE itself points out that banked RECs provide an important balancing mechanism, potentially enabling them to delay the addition of physical resources and the associated investment costs.[10] Notwithstanding, PGE did not analyze how using unbundled RECs to meet the RPS between 2015 and 2019 would affect PGE's costs and risk.

PGE has a lengthy discussion on the alternative minimum compliance payment as the only alternative to adding additional resources. Staff believes this is simply not the case; the alternative minimum compliance payment (AMCP) is approximately \$50/MWh.[11] At this time, the unbundled REC market is well below the AMCP. Staff concludes that a combination of unbundled and bundled RECs should be considered in a least cost/risk RPS compliance strategy.

PGE claims that there may be significant future increases in the cost of building new renewables. To illustrate its point, PGE assumes a straight-line growth rate of 7.8 percent on an average annual basis that would supposedly increase costs from 93.62/MWh to \$141/MWh in 2009\$.[12] However, PacifiCorp recently filed for an RFP in UM 1429 and UM 1360 citing a reduction in the price of commodities and construction costs. PacifiCorp stated that it believed that as a result of the economic downturn, more favorable bids may be received now than were provided in December 2008.[13]

PacifiCorp's recent filing illustrates the up-and-down business cycle that any market faces, and shows that PGE's assumptions of straight-line appreciation with regard to the construction and turbine manufacturing industry are highly speculative. PGE's assumptions also discount potential technological innovations in the renewable market, such as accelerator wind turbines, which may change the landscape of renewable resource costs in the near future.

PGE proposes to conduct an RFP for its acquisition of 122 MWa of renewable resources. Staff agrees with PGE that RFPs provides the Company an opportunity in the procurement process to

[9] PGE IRP at 116.

[10] PGE IRP at 116.

[11] *See* Order No. 09-200.

[12] *See* PGE IRP at119-20.

[13] *See* UM 1360, PacifiCorp's Request to Resume 2008 RFP at 2.

allow selection of the least-cost renewable resource. However, Staff recommends that PGE develop a RFP strategy that provides PGE flexibility to test the market at different times in order to determine currently available technology, sites, and construction cost estimates so as to be more prepared to take advantage of opportunities in any given economic climate.

Wind integration study

Recommended Requirement:

> *In its next IRP Update and in the next IRP planning cycle, PGE must include a wind integration study that has been vetted by regional stakeholders.*

In the Commission's order regarding PGE's 2007 IRP, the Commission ordered PGE to "include in the [next IRP] analysis a wind integration study that has been vetted by regional stakeholders."[14] PGE did not comply with this directive. Rather than allowing stakeholders to "vet" its wind integration study, PGE made a power-point presentation in September 2008 regarding its initial wind-integration study that included few details of PGE's analysis.[15] PGE has not produced a study whose detailed methodology and results have been made available for review.[16]

Staff recommends that the Commission repeat its directive to PGE to prepare a wind integration study, and that the Commission direct PGE to do so in its next IRP and in the next planning cycle.

Reliability

Recommended requirement:

> *In its next IRP Update and all subsequent IRPs, PGE must fully comply with all requirements of Guideline 11.*

Guideline 11 requires an electric utility to:

a. Analyze reliability within the risk modeling of the actual portfolios being considered;

b. Determine by year the loss of load probability (LOLP), expected planning reserve margin, and expected and worst-case unserved energy for top-performing scenarios; and

c. Demonstrate that the selected portfolio that achieves the utility's stated reliability, risk and cost objectives.

---

[14] OPUC Order No. 08-246 at 10.

[15] *See also,* May 19, 2010 RNP Comments at 2.

[16] See also, Sept. 1, 2010 RNP Comments at 1.

Staff agrees with NWEC that PGE's expected unserved energy (UEU) metric is a market exposure metric and not a valid reliability metric. PGE calculates a *conditional* expected unserved energy value (CEUE). PGE's CEUE is defined as the *per-hour* average MWa's purchased during the hours that the Company must go to the spot market to meet customer load. A more useful reliability measure would be the "Average [i.e., expected] Annual Energy Not Served (ENS)," which is a major reliability measure used by PacifiCorp in its IRP. This *annual* figure is obtained by *not* dividing the cumulative spot-market-purchased MWa's by the number of hours in the year when such purchases are needed.

The problem with PGE's CEUE is that a portfolio can get a low EUE score, but due to having a very high LOLP get a high ENS score. In other words, a particular portfolio may suffer from many hours of outages (i.e., have a very high LOLP), but, due to the amount of compensatory spot market purchases *per hour* being low, that portfolio would, undeservedly (since the ENS score would be high), get a favorable EUE score.

PGE did incorporate a measure of WCEUE into the cost and risk metrics used to score the competing portfolios, but the measure, labeled TailVar 90 Unserved Energy, is conceptually flawed. While interesting, this metric is subject to the same criticism that applies to the Company's measure of CEUE. PGE's TailVar 90 Unserved Energy for a given portfolio consists of the average of the ten worst EUEs (as calculated above) out of the 100 stochastic iterations. The deficiency in this metric is that a particular portfolio may get a bad (i.e., high) score for this metric, but in conjunction with a very low LOLP, have a comparatively attractive "worst-case unserved energy" in an annual, statistically expected sense. As above, a more useful would be a TailVar 90 score based on the 10 percent worst annual *sums* (i.e., not the *average* hourly figures) of energy not served.

Performance measures

Guideline 4 calls for the evaluation of the portfolios' comparative exposures to risks and uncertainties.[17] While PGE does evaluate risk and uncertainty, PGE persists in using two performance measures, "Average of Worst Four Futures Less the Reference Case Costs," and "TailVar 90 Less the Mean" that can be misleading.

PGE states that it measured magnitude of risk with what Staff will call the "Average of Worst Four Futures Less the Reference Case Costs," a performance measure that focuses on the average expected cost of the worst four futures for each portfolio less the reference case expected

[17] Guideline 4 provides, in pertinent part: At a minimum, the plan must include the following elements: … i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties; j. Results of testing and rank ordering of the portfolios by cost and risk metric and interpretation of those results; and k. analysis of the uncertainties associated with each portfolio evaluated.

cost.[18] The "Average of Worst Four Futures" is the average of the projected 30-year net-present-value (NPV) discounted costs experienced by a given resource portfolio in the event of the four futures (i.e., combinations of natural gas prices, CO2 compliance costs, capital costs, etc.) that generate the highest costs for that portfolio. The "Reference Case" is what the Company actually expects to be the costs of the portfolio.[19]

The "TailVar 90 Less the Mean" is a stochastic metric PGE uses to evaluate exposure to risk. TailVar 90 Less the Mean is a stochastic metric and looks at the performance of the portfolios using stochastic inputs for five risk variables: weather impacts on loads, natural gas prices, forced plant outages, wind intermittency, and hydro conditions.[20] The "TailVar 90" denotes the average of the 10 highest-cost outcomes out of 100 independent iterations of the stochastic inputs. The "Mean" is the average of those 100 iterations for each resource portfolio.
Both measures subtract the mean or reference case value from the extreme or bad value(s). Rather than simply conveying how bad things might be, which is done by the performance measures suggested by OPUC Staff, i.e., "Risk Magnitude: Avg. Worst 4" and "Risk: TailVar," the measures at issue can register a good score if the mean is also bad, i.e., high.[21]

The following table illustrates this problem: (from Table 11A-2 of the PGE Addendum):

Resource Portfolio	Reference Case $ NPV Million	Avg. Worst 4 $ NPV Million	Avg. Worst 4 vs. (i.e., Minus) Reference Case $ NPV Million
Diversified Thermal with Green	34,910	28,674	**6,236**
Boardman thru 2020	34,770	28,396	**6,374**

"Diversified Thermal with Green" gets the <u>better</u>, i.e., lower, raw score ($6,236 vs. $6,374) *even though <u>both</u> its reference case value <u>and</u> the average of its worst four outcomes are <u>worse</u> than the respective values* for "Boardman thru 2020." The portfolio that is clearly inferior with regard to these risk and outcome measures, i.e., "Diversified Thermal with Green," should not receive a

[18] PGE IRP at 257.

[19] PGE IRP at 257-58.

[20] PGE IRP at 265.

[21] PGE performed the metrics suggested by Staff. *See* PGE IRP at 261 and 266.

superior *composite* score. The described "distortion" would not occur if the risk measure was simply the "Avg. Worst 4" by itself (as recommended by Staff).

Gas price forecast

Recommendation: *PGE should obtain gas price forecasts from multiple third-party, expert, sources, rather than relying on forecasts from one such source.*

PGE clearly recognizes the importance of natural gas-fired generation in the Oregon and its own power supply portfolio. PGE also recognizes the importance of properly forecasting future natural gas prices as part of a well prepared IRP. PGE notes,

> Our general approach to projecting fuel prices is to develop a reference-case fuel price forecast based on near-term market indications and longer-term fundamentals, as determined by third-party, expert sources. For this IRP, we utilized independent third-party fundamental research and price forecasts from PIRA Energy Group for both coal and natural gas.[22]

By relying on long-term forecasts from only one source, PIRA Energy Group (PIRA), PGE does not adequately account for the biases that underlie PIRA's gas price forecasting and the results of those biases for the forecast. Every forecasting company or agency has its own particular group of biases. PIRA is no exception.

PIRA's bias is clearly seen when the PIRA reference case Henry Hub forecast is compared to the reference case forecasts for that same Hub by the U.S. Energy Information Administration (EIA) and Wood MacKenzie Research and Consulting (Wood MacKenzie). PIRA's reference case values stand well above those for both the EIA and Wood MacKenzie over the entire planning period, and particularly after 2014. This is not surprising considering PIRA's usual group of biases compared to those of the EIA and Wood MacKenzie. However, PIRA's low case price forecast compares favorably with EIA's and Wood MacKenzie's reference cases.

PGE's long-term gas price forecast can be improved in at least two ways. First, PGE can undertake its own research to assess PIRA's biases and remove them in the forecast. This is difficult and time consuming, but it is possible. A second, and what Staff believes is a more appropriate means to address PIRA's biases, is to integrate forecasts from additional third-party, expert sources with PIRA's forecasted gas prices to obtain a reasonable range of natural gas price forecasts.

Staff has the same concern with PGE's sole reliance on the New York Mercantile Exchange (NYMEX) for natural gas "near-term market indications." NYMEX is one indicator of short-term prices, but only one. In addition to NYMEX PGE should rely on other fundamental sources

[22] PGE IRP at 75.

for short-term price indicators. Instead, PGE relies on no "fundamental" source for such indications.

PGE obtains futures prices at the Henry Hub from NYMEX. PGE uses basis differentials to convert Henry Hub prices to those expected at northwest natural gas market hubs. However, as NYMEX notes on its website, it is not a forecasting source. Accordingly, PGE's reliance on NYMEX for short-term price indications is flawed not only because it is a single source, but because it is not even a fundamental source.

CONCLUSION

Staff has completed an IRP Guideline analysis and has determined that PGE has met the Commission's IRP Guidelines. For further detail on how the Company complied with each guideline, please see Appendix A.

DATED this 15 day of October 2010.

Respectfully submitted,

Maury Galbraith
Acting Administrator
Electric and Natural Gas Division

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
LC 48

In the Matter of PORTLAND GENERAL ELECTRIC 2009 Integrated Resource Plan.	DRAFT PROPOSED ORDER[1]

DISPOSITION: PLAN ACKNOWLEDGED

I. INTRODUCTION

Portland General Electric Company (PGE) seeks acknowledgment of its 2009 Integrated Resources Plan (IRP) and 2010 Addendum. We acknowledge the plan subject to certain requirements that are discussed below.

A. IRP Guidelines

We require regulated energy utilities to engage in integrated resource planning and to file an IRP every two years. We review the filed plans to determine whether they adhere to our IRP guidelines and either "acknowledge" them, or return to the utility with comments. Acknowledgement does not guarantee favorable ratemaking treatment, but means that the plan seems reasonable at the time of Commission review.

The Commission has set forth thirteen IRP guidelines. The first guideline includes substantive requirements under which the utility must (1) evaluate all resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) have as its primary goal 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; and (4) draft a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[2] The remaining twelve guidelines set forth procedural and other requirements that provide direction on how to prepare and update the plan and regarding specific resources such as transmission and conservation.

B. Procedural history.

Portland General Electric Co., (PGE) filed its 2009 Integrated Resource Plan (IRP) on November 5, 2009. Following a prehearing conference on December 1, 2009, the administrative law judge (ALJ) issued a procedural schedule calling for a PGE

[1] The Commission Staff prepares draft proposed orders in LC Dockets. Neither the Commission nor the Administrative Hearings Division has reviewed this proposed order. The Commission will take the proposed order, and any revisions recommended by Staff and intervenors, under advisement at the November 12, 2010 Special Public Meeting.
[2] OPUC Order No. 07-002.

presentation to the Commission on January 19, 2010, intervenor comments in February 2010, PGE reply comments and Staff recommendations and proposed order in March 2010, and Commission consideration at a May 25, 2010 public meeting.

On January 14, 2010, PGE asked the Commission to defer consideration of PGE's plan to invest over $500 million to retrofit its Boardman coal-fired plant to meet requirements of the Oregon Environmental Quality Commission's (EQC) Regional Haze Plan and asked the Commission to postpone PGE's presentation to the Commission scheduled for January 19, 2010. PGE explained that it intended to meet with stakeholders to assess whether PGE could devise alternatives to its proposal to invest over $500 million to retrofit Boardman and operate the plant until 2040 that would be acceptable to the EQC and other stakeholders. On January 15, 2010, the Commission stayed all proceedings in Docket No. LC 48.

On April 9, 2010, PGE filed an addendum to its IRP outlining revisions to its IRP regarding Boardman. Subsequently, the ALJ adopted a procedural schedule that called for a PGE presentation to the Commission in April 2010, intervenor comments on May 19, 2010, PGE reply comments on June 11, 2010, Staff comments and proposed order as well as PGE and intervenor reply comments in July 2010, and Commission consideration at a public meeting in August 2010.

Prior to the time PGE filed its comments replying to May 19, 2010 intervenor comments, Staff asked the ALJ to abate the procedural schedule to allow opportunity for PGE, intervenors, and Staff to consider whether certain EQC and Department of Environmental Quality (DEQ) actions impact their recommendations to the Commission regarding PGE's IRP. Staff pointed out that on June 17, 2010, the EQC would consider (1) PGE's request to modify the EQC's 2009 Regional Haze Plan in a manner that would allow PGE to pursue its revised operating plan for Boardman, and (2) DEQ's recommendation that the EQC direct DEQ to base analysis regarding potential revisions to the Regional Haze Plan on a range of operating options for Boardman, rather than on the single operating plan underlying PGE's proposed rule change. The Commission granted Staff's motion and scheduled a pre-hearing conference for July 1, 2010, for the purpose of setting a new procedural schedule.

The ALJ adopted a procedural schedule at the July 1, 2010 prehearing conference requiring PGE to file reply comments analyzing three DEQ-proposed alternatives for Boardman retrofits and operation and responding to the May 19, 2010 intervenor comments. The procedural schedule gave intervenors opportunity to respond to PGE's supplemental comments, PGE opportunity to file reply comments on September 27, 2010, and directed staff to file recommendations and a proposed order on October 11, 2010, with Commission consideration at the November 9, 2010 public meeting.

On September 21, 2010, the Commission issued a bench request directing PGE to file additional analysis regarding the three DEQ retrofit and operation scenarios and allowing intervenors the opportunity to reply to PGE's response to the bench request. On October 7, 2010, the ALJ granted Staff's request to postpone the due date for Staff recommendations and proposed order, as well as the due date for reply comments by intervenors and PGE, and to schedule a special public meeting on November 12, 2010, to consider Docket No. LC 48.

In sum, the procedural schedule in this docket allowed three rounds of intervenors' comments and an opportunity for PGE to file an addendum to its IRP as well as the opportunity to file three rounds of reply comments and respond directly to the Commission's bench request. In addition, the procedural schedule included two technical workshops attended by the Commission, one addressing PGE's proposal for a new transmission line and the other addressing Boardman; three other opportunities for PGE to present to the Commission at public meetings, two opportunities for intervenors to present to the Commission at public meetings, and two public comment hearings, one in Portland and one in Boardman, at which the Commission did not allow PGE to comment.

C. Parties.

The following entities intervened in this proceeding: Northwest and Intermountain Power Producers Coalition, Citizens' Utility Board of Oregon, NW Energy Coalition, Ecumenical Ministries of Oregon, Oregon Environmental Council, PacifiCorp, Iberdrola Renewables, Inc., Oregon Department of Energy, Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, Northwest Environmental Defense Center, Renewable Northwest Project, Physicians for Social Responsibility, Northwest Pipeline GP, City of Portland, Industrial Customers of Northwest Utilities, Turlock Irrigation District, International Brotherhood of Electrical Workers Local 125, Northwest Food Processors Association, Portland Metropolitan Building Owners and Managers Association, Oregon Forest Industries Council, Oregon Cattlemen's Association, Willard Rural Association, Power Resources Cooperative, Salem Area Chamber of Commerce, Strategic Economic Development Corporation, Clackamas County Business Alliance, Columbia Corridor Association, Associated Oregon Industries, Westside Economic Alliance, Portland Business Alliance, Association of Oregon Counties, Wilsonville Chamber of Commerce, Morrow County, Oregonians for Food and Shelter, Oregon Farm Bureau, Community Action Partnership of Oregon, and Pareto Energy, LTD.

In addition, well over one thousand people filed written public comments with the Commission. Many of the comments are form letters that the Commission received at the public comment hearings held in Boardman and Portland. More than 800 form letters support closure of Boardman by 2014. More than 250 form letters support operating Boardman through 2040, or at the minimum, through 2020.

II. Discussion.

Boardman.

Parties' Positions: PGE requests that the Commission acknowledge continued coal-fired operations at Boardman with compliance actions to meet Oregon Regional Haze Plan and Oregon Utility Mercury Rule standards. The proposed compliance actions at the Boardman plant include:

1. Installation of low-nitrogen oxide (NOx) burners with a modified overfire air control system in July 2011;
2. Installation of mercury controls in July 2012;
3. Installation of selective non-catalytic reduction (SNCR) in July 2014;
4. Operation using reduced sulfur coal beginning in July 2014;
5. Installation and pilot testing of a Dry Sorbent Injection (DSI) system in July 2014; and
6. Cessation of coal-fired operations at the end of 2020.[3]

These compliance actions comprise PGE's BART III proposal submitted to the DEQ on July 30, 2010. Contingent on the results of the DSI pilot testing, PGE would commit to meeting a 0.4 lb. sulfur dioxide (SO_2) per million British thermal unit (MMBtu) emission limit through 2020 using DSI. If the pilot testing demonstrated that operating the plant with DSI technology is incapable of achieving this level of SO_2 emissions without triggering an increase in emissions of particulate matter, then PGE proposes to meet an alternative SO_2 limit established by DEQ procedure based on the DSI testing. It is unclear whether the EQC will adopt PGE's BART III proposal.

In comments filed in this docket on August 10, 2010 and September 27, 2010, PGE argues that its BART III compliance actions, when combined with its energy efficiency, renewable energy, and other resource actions, comprise a portfolio of resources that provide the best combination of cost and associated risk for ratepayers over the IRP planning period.

PGE analyzed its BART III proposal, as well as three alternative DEQ options, using its IRP portfolio modeling. DEQ Option 3 calls for installation of a low-NOx burner system in 2011 and mercury controls in 2012; but would require the shutdown of the Boardman plant by late 2015 or early 2016. DEQ Option 2 is similar to PGE's BART III proposal, but would result in cessation of coal-fired operations in 2018. DEQ Option I includes the low-NOx burner system in 2011, the mercury controls in 2012, adds installation of semi-dry flue gas desulfurization (dry scrubbers) in 2014 to control SO_2 emissions, and would cease coal-fired operations at Boardman in 2020. Based on its IRP modeling, PGE concludes that its BART III resource portfolio is both less costly and less risky than the three DEQ options.[4]

---

[3] PGE's August 10, 2010 Comments at 8-9.
[4] PGE's August 10, 2010 Comments at 11-13.

PGE observes that among the early closure options, those that keep Boardman open longer perform better. PGE suggests that DEQ Option 1 is unacceptable because the dry scrubbers are a very costly additional layer of control. PGE questions the regulatory implementation of DEQ Option 2, which does not include pilot testing of the DSI technology, and therefore fails to account for the possibility that achieving the SO_2 emission limit may simultaneously trigger a violation of particulate matter limits. Finally, PGE argues that DEQ Option 3, which would shutdown Boardman in late 2015 or early 2016, offers an extremely poor outcome for ratepayers in terms of cost and risk.

PGE urges the Commission to acknowledge the compliance actions in its BART III proposal as being the least cost and least risk option for ratepayers. PGE believes these actions define a reasonable transition to non-coal fuel resources and would set national precedent.[5]

PGE concedes that its BART III proposal does not guarantee that future regulation of hazardous air pollutants or the resolution of pending litigation in United States District Court will not require PGE to install additional controls at Boardman prior to 2020. However, PGE no longer makes its acknowledgment request contingent upon obtaining a reasonable assurance by March 31, 2011 that it will be able to operate Boardman through 2020 without installing additional emission control technologies. PGE asks the Commission to acknowledge its BART III compliance actions despite these risks.[6]

PGE does, however, make its acknowledgement request contingent on EQC approval of its BART III proposal by March 31, 2011. In the event that the EQC fails to approve BART III, PGE requests acknowledgement of a backstop proposal. PGE's backstop is full implementation of BART I controls and continued operation of the Boardman plant through a least 2040. Based on incremental rate impact analysis, PGE concludes that the BART I emission controls, as modeled in the Diversified Thermal with Green portfolio, outperform the three DEQ early shutdown options and is the second best option for ratepayers.[7]

PGE argues that backstop acknowledgment is necessary because any delay in ordering the equipment needed to implement BART I will subject ratepayers to increased costs and risks associated with a compressed Engineering, Procurement and Construction (EPC) schedule and with a potential temporary shut-down of the Boardman plant in 2014 as a result of failure to install the dry scrubbers by the BART I deadline.[8] PGE has continuously emphasized throughout this proceeding that failure to comply with the Oregon Regional Haze Plan is not an option. The Boardman plant must meet the emissions requirements by either installing the required controls or by ceasing coal-fired operations.

[5] PGE's August 10, 2010 Comments at 52.
[6] PGE's August 10, 2010 Comments at 16.
[7] PGE's August 10, 2010 Comments at 15.
[8] PGE's August 10, 2010 Comments at 5 and IRP Addendum at 124.

The following parties submitted comments that largely support PGE's BART III proposal without qualification: Morrow County Commission, Portland Business Alliance, Oregon Forest Industries Council, Associated Oregon Industries, Oregon Cattlemen's Association, Community Action Partnership of Oregon, Strategic Economic Development Corporation, Association of Oregon Counties, Salem Chamber of Commerce, Wilsonville Chamber of Commerce, Clackamas County Business Association, Columbia Corridor Association, Oregon Farm Bureau and Oregonians for Food and Shelter. IBEW Local 125 urges the Commission to acknowledge operation of the Boardman plant until 2040 and beyond, with nothing less than 2020 as a backstop. The Physicians for Social Responsibility urge the Commission to consider the serious health concerns and costs associated with continued operation of the Boardman Coal Plant beyond 2014.

Other parties submitted comments that challenged PGE's analysis of the Boardman compliance options and contained alternative recommendations for the Commission. We summarize these parties' positions below.

The Coalition

The Sierra Club, National Environmental Defense Center (NEDC), Friends of the Columbia Gorge, and Columbia Riverkeeper (the Coalition) characterize PGE's proposed compliance actions as a plan to transition off coal in 2020 or never.[9] The Coalition argues that PGE's proposed BART III is virtually identical to its BART II proposal that was already rejected by the EQC. The Coalition recommends that the Commission order PGE to start over and develop a balanced and reasonable outcome for Boardman that is consistent with clean air laws and Oregon's greenhouse gas emissions reduction goals.

The Coalition argues that PGE's own modeling shows that compared to PGE's BART I backstop both DEQ Option 2, with early shutdown in 2018, and DEQ Option 3, with early shutdown in late 2015, are lower cost alternatives.[10]

The Coalition argues that PGE uses unreasonably high natural gas prices in its IRP modeling and biases the results in favor of continued operation of the Boardman plant and against the early shutdown scenarios.[11] The Coalition concedes that it did not prepare its own natural gas prices forecasts, but instead relied upon the forecasts provided in the record of this proceeding by other parties. However, the Coalition argues that it is critically important that planning analyses and decisions be based on current information. The Coalition recommends that the Commission require PGE to update its reference case natural gas price forecast before accepting the modeling results.

The Coalition also claims that PGE has overstated its energy and capacity needs.[12] Again emphasizing the importance of current information, the Coalition argues that PGE should

[9] Coalition's September 1, 2010 Comments at 1-2.
[10] Schlissel Technical Consulting September 1, 2010 Comments at 2-6.
[11] Schlissel Technical Consulting September 1, 2010 Comments at 7-16.
[12] Schlissel Technical Consulting September 1, 2010 Comments at 16-18.

use its December 2009 peak and average energy load forecasts in its IRP modeling. The Coalition argues that the differences between the December 2009 forecasts and the March 2009 forecasts used in PGE's IRP modeling are significant and material to the development of PGE's IRP Action Plan.

The Coalition opines that contrary to PGE's assertions, a natural gas-fired combined-cycle combustion turbine (CCCT) can be built in two to two- and-a-half years.[13] Given actual construction times, the Coalition believes that a CCCT could be built and ready to replace Boardman by 2016.

The Coalition states that PGE has completely failed to evaluate the economic cost and benefits of replacing some or all of Boardman's output with a mid-term power purchase agreement (PPA).[14] According to the Coalition a mid-term PPA strategy could be used to implement DEQ Options 2 & 3.

The Coalition points to PGE's IRP modeling which shows Boardman operating as an intermediate-load resource in the future and questions the prudence of investing in emissions controls at the plant if it would no longer operate as a baseload resource.[15]

The Joint Parties

The Citizens' Utility Board (CUB), Renewable Northwest Project (RNP), NW Energy Coalition (NWEC), Oregon Environmental Council (OEC), Angus Duncan, Ecumenical Ministries of Oregon (EMO), Sierra Club, and NEDC, (collectively, "the Joint Parties"), have one simple recommendation for the Commission, do not acknowledge the BART I emission controls, as modeled in the Diversified Thermal with Green portfolio or any other portfolio, even as a backstop plan.[16] Installing these emissions controls and hoping to run the plant through 2040 is viewed as the most objectionable option before the Commission.

The Joint Parties support closing the Boardman plant as early as possible, yet indicate that they would prefer a broadly supported plan, even if the plan closed the plant at a somewhat later date. Therefore, PGE and DEQ are urged to use DEQ's Option 2 and PGE's BART III proposals as the basis for achieving convergence on a broadly supported plan. The Commission is urged to only acknowledge the pollution controls that are immediately necessary and to leave the door open for further amendments to this IRP. According to the Joint Parties these actions will allow room for PGE, DEQ, and other stakeholders to agree on a comprehensive plan to achieve the responsible closure of Boardman.

[13] Schlissel Technical Consulting September 1, 2010 Comments at 18.
[14] Schlissel Technical Consulting September 1, 2010 Comments at 19.
[15] Schlissel Technical Consulting September 1, 2010 Comments at 20-21.
[16] Joint Parties September 1, 2010 Comments at 1.

The Joint Parties argue that the replacement of Boardman should be significantly cleaner and more flexible than replacement with only a baseload natural gas plant.[17] The Joint Parties are confident that PGE could replace Boardman in the 2015/2016 timeframe with a diverse mix of resources. However, they concede that early closure risks replacement with a natural gas resource and its associated carbon emissions. Again, the Joint Parties urge the Commission to create space for stakeholders to develop a clean and diverse replacement strategy.

In summary, the Joint Parties seek early closure of the Boardman plant, a replacement strategy with a clean and diverse mix of resources, and broad consensus among stakeholders; while simultaneously protecting ratepayers and keeping the cost of closure and replacement power under control.

The NW Energy Coalition

NWEC joins the Joint Parties in recommending shutdown of the Boardman plant by no later than 2020. Like the Joint Parties, NWEC prefers an agreement between PGE, DEQ, and stakeholders on an acceptable plan. As a result, NWEC recommends that the Commission only indicate the boundaries of an acceptable closure plan. According to NWEC, formal acknowledgement should only occur after an actual agreement to close Boardman is achieved.[18]

NWEC opines that not enough effort has been put into developing a resource strategy to replace Boardman.[19] NWEC urges the Commission to consider the state's carbon reduction goals and in the next IRP cycle to begin working on a comprehensive plan to achieve significant reductions in emissions. NWEC has repeatedly argued that the risk metrics used by PGE in its IRP portfolio analysis assign no weight to the risk of carbon regulation because they average scenarios with high and low carbon costs. NWEC recommends that the Commission require future IRPs to include a risk metric that directly measures carbon dioxide emissions.

NWEC is most forceful in its objection to PGE's request for backstop acknowledgment of the BART I compliance actions.[20] NWEC argues the DEQ Option 3 with closure of Boardman in late 2015 or early 2016 is the better backstop. According to NWEC a comparison of the modeling results of PGE's BART I backstop to DEQ Option 3 shows no significant difference on a cost basis. NWEC argues that the lower carbon dioxide emissions of DEQ Option 3 should be used to break this tie. NWEC suggests that the advantage in emissions could be even larger if Boardman is replaced with power sources cleaner than a natural gas-fired CCCT. NWEC scolds PGE for introducing new factors, such as near-term rate impacts, inadequate time to develop replacement resources, and insufficient transition time for its employees and the Boardman community, as tie-breaking criteria.

[17] Joint Parties September 1, 2010 Comments at 2.
[18] NWEC September 1, 2010 Comments at 1.
[19] NWEC September 1, 2010 Comments at 1-2.
[20] NWEC September 1, 2010 Comments at 2-6.

Although NWEC joins the Coalition in questioning PGE's timeline for construction of a CCCT, it more fundamentally questions the need for immediate and full replacement of Boardman's capacity and energy output.[21] NWEC has repeatedly argued that the load forecast used by PGE in its IRP modeling is higher than the Northwest Power and Conservation Council's Oregon (NPCC) forecast. NWEC also asserts that PGE has overstated its resource need by deciding to lower its exposure to the wholesale power market. NWEC criticizes PGE for not analyzing its level of market exposure in this IRP. NWEC concludes that there is little need for quick and full replacement of Boardman by 2015.

Finally, NWEC concedes that over reliance on the wholesale power market can be risky and detrimental to ratepayers. It then points to a healthy surplus of generating capacity in the Northwest and the area covered by the Western Electricity Coordinating Council and concludes this risk is worth taking to close Boardman in late 2015 or early 2016. NWEC argues that reliance on the market can provide the space needed in time to acquire a clean mix of replacement resources.

NIPPC

The Northwest and Intermountain Power Producer's Coalition (NIPPC) offers no opinion regarding the cessation of coal-fired operations at the Boardman plant.[22] NIPPC emphasizes, however, that the shutdown risks being debated in this proceeding are largely ratepayer risks and opines that diversifying ownership of generation resources is in the best interest of ratepayers. NIPPC says it is well established that power purchase agreements (PPAs) lower a utility's business risk. Contrasting PGE's Boardman ownership with PGE's PPA with TransAlta for a portion of the output of the coal-fired Centralia plant, NIPPC concludes that power secured through a PPA with an independent power producer is far less risky for ratepayers.[23]

NIPCC offers more detailed criticism of PGE's analysis of the potential replacement resources for Boardman. NIPPC argues that PGE has not adequately evaluated the costs and risks, including the reliability risks, of entering into power purchase agreements with independent power producers. NIPPC's criticism is not limited to the evaluation of PPAs for long-term replacement of Boardman, but also covers the evaluation of short-term PPAs that could temporarily bridge the capacity and energy need until a permanent replacement is built or purchased. According to NIPPC, PGE's repeated assertions that this type of analysis is more appropriate in a competitive procurement proceeding are misplaced. Commission IRP Guideline 1 requires utilities to evaluate all resources on a consistent and comparable basis.[24] NIPPC argues that postponement of the evaluation of PPAs to the competitive bidding process makes PGE's IRP noncompliant with IRP Guideline 1.

[21] NWEC September 1, 2010 Comments at 4.
[22] NIPPC September 1, 2010 Comments at 2.
[23] NIPPC September 1, 2010 Comments at 7.
[24] OPUC Order 07-002 at 3.

NIPPC has specific recommendations to remedy PGE's lack of analysis of the PPA option. NIPPC asks the Commission to require PGE to issue a Request for Information (RFI) to potential suppliers of replacement power.[25] This streamlined information gathering process would allow PGE to adequately consider the PPA resource and to re-evaluate its replacement options. NIPPC states that PGE should be required to file an IRP addendum explaining the results of the RFI and to allow parties to fully vet the merits of the PPA replacement option.

NIPPC also has recommendations for improving PGE's upcoming Request for Proposal (RFP) process.[26] Concerned that PGE intends to favor its own self-built benchmark resources, NIPPC recommends the Commission encourage PGE to identify the actual amount of nameplate megawatts that it intends to acquire through unit contingent PPAs linked to resources that PGE does not intend to build or subsequently acquire. NIPPC also recommends that the Commission strongly encourage PGE to solicit bids that include build-to-own replacement options at PGE's sites, long-term PPAs linked to replacement resources located at non-PGE sites, as well as sales of existing assets from independent power producers.

Staff

Staff recommends that the Commission acknowledge PGE's BART III proposal. Staff recommends that the Commission not acknowledge PGE's BART I backstop proposal, but instead require PGE to include a backstop proposal and supporting analysis in its next IRP Update if EQC denies its request to revise the Regional Haze Program to facilitate PGE's BART III proposal.

Staff primarily focused its analysis of PGE's portfolio modeling on three metrics, expected cost, the average of the four worst deterministic futures, and the stochastic TailVar90 risk metric. Staff also reviewed the analysis and comments of the other parties in this case. Based on this analysis, Staff agrees with PGE that its BART III proposal represents the portfolio with the best combination of cost and risk for ratepayers. The BART I portfolios, including Diversified Thermal with Green, would impose too great of a risk on ratepayers from future federal and state regulation of carbon emissions. Staff also agrees with PGE that the execution risks associated with implementing the earlier shutdown scenarios are also significant.

While Staff agrees with NIPPC and NWEC that power purchases from independent power producers or the wholesale power market could be used to bridge the early energy and capacity deficits associated with these scenarios, Staff concludes that the risk associated with this type of strategy is not in the best interest of ratepayers. For these reasons, Staff recommends that the Commission acknowledge PGE's BART III proposal.

[25] NIPPC September 1, 2010 Comments at 5.
[26] NIPPC September 1, 2010 Comments at 8-9.

Staff agrees with comments of other parties that that there is evidence that PGE's reference case load forecast may overstate future demand. However, Staff's analysis indicates that PGE's energy and capacity need remains significant even under a lower load scenario. Under PGE's reference case load forecast, with Boardman operating, PGE is short 952 annual average megawatts (MWa) of energy in 2016. Staff notes that shutting down Boardman in late 2015 would push that deficit to 1,266 MWa in 2016. Updating PGE's model to include its low load scenario, with Boardman shutdown in 2015, the resource deficit would be 1,158 MWa in 2016. The winter and summer capacity deficits under this low load scenario without Boardman are 1,979 MW and 1,788 MW, respectively. Staff asserts that these resource gaps are significant and would be challenging to fill if Boardman were shut down in 2016.

Staff agrees also with the Coalition and NWEC that PGE's reference case natural gas price is slightly overstated. However, Staff concludes that PGE's response to the Commission's bench request, which tested a combined low natural gas price, low load forecast scenario, continues to show very little difference between the shutdown scenarios on an expected cost basis. Staff prefers PGE's BART III proposal because it allows adequate time to implement a lower-risk replacement resource strategy.

Commission resolution: In response to the concerns raised by the Coalition, NWEC, the Joint Parties, and EMO regarding the load and natural gas price forecasts used in PGE's IRP modeling, we sent a bench request to PGE on September 21, 2010. Comments submitted by PGE on September 27, 2010 and PGE's response to our bench request have satisfactorily addressed our concerns.

While there is evidence that PGE's reference case load forecast may overstate future demand, PGE and Staff have convincingly rebutted assertions that this significantly impacts the need for capacity and energy in PGE's IRP. PGE correctly points out that it is traditional practice in Oregon IRP to present the gap between forecasted load and existing resources prior to adding any proposed demand- or supply-side resource actions.[27] Staff has presented incremental load-resource balance results, first assuming Boardman is shutdown in late 2015, and then using PGE's low load forecast. Under PGE's reference case load forecast, with Boardman operating, PGE is short 952 annual average megawatts (MWa) of energy in 2016. Shutting down Boardman in late 2015 would push that deficit to 1,266 MWa in 2016. Under PGE's low load scenario, with Boardman shutdown in 2015, the resource deficit would be 1,158 MWa in 2016. The resource actions needed to fill this gap, if Boardman is in fact shutdown, are significant and not likely to disappear with further updates of PGE's load forecast.

The Coalition and NWEC also raised concerns regarding PGE's reference case natural gas price forecast. While PGE's natural gas price forecast may be overstated, we are also concerned that the reference case trajectory of future carbon dioxide (CO_2) prices may also be overstated. We are aware of the biases that can occur when selectively updating forecasts and assumptions in an IRP without considering the relationship of the update to

[27] PGE September 27, 2010 Comments at 12.

other variables in the model. For example, we would expect a positive correlation between CO2 prices and natural gas prices because the imposition of stringent carbon regulation would likely increase the demand for natural gas.

Accordingly, our bench request asked for a combined sensitivity analysis that included lower load and natural gas price forecasts and a lower trajectory for future carbon dioxide prices. We have examined the results of the bench request analysis and note that BART I and DEQ Option 1 continue to be the highest cost portfolio options. While the relative performance of DEQ Option 2 improves under our combined sensitivity, we are convinced that this portfolio's biggest drawback is execution risk. BART III and DEQ Option 3 continue to be closely ranked options.

Two other modeling issues directly impact the Boardman analysis. First, the Coalition raised the issue of whether it would be prudent to invest in pollution control equipment at Boardman when the IRP modeling shows the plant operating at reduced annual capacity factors in the future. But, as PGE points out, the reduced dispatch is reflected in The IRP analysis.[28] Furthermore, the declining dispatch, which is the result of high carbon dioxide prices late in the planning period, is not a relevant issue when comparing the early shutdown options. Second, NWEC and the Joint Parties assert that PGE's risk analysis effectively assigns no weight to the risk of future carbon regulation because scenarios with high CO_2 prices are offset by scenarios with low CO_2 prices. PGE convincingly rebuts this argument.[29] The risk metrics that we consider to be primary, the average cost of the worst four deterministic futures and the stochastic TailVar90 metric, do not combine or average high and low CO_2 price futures.

There is a wide divergence of opinion regarding the appropriate fuel mix and associated execution risk of resources that could be used to replace Boardman. Although PGE states that the evaluation of replacement resources is the appropriate subject of a future IRP, the company has doggedly defended its proxy replacement resource, a natural gas CCCT, against other replacement options.[30] PGE has steadfastly argued that any replacement resource needs to be another baseload resource. PGE has emphasized the execution risk associated with acquiring replacement resources by early 2016. According to PGE, the development and execution of a replacement strategy that relies on a broad mix of renewable resources would likely require a timeline that extends beyond 2016.

The Coalition argues that a natural gas CCCT could be built and ready to replace Boardman by 2016. NIPPC and NWEC argue that PGE should more fully consider market purchases as a potential replacement resource. Purchases from independent power producers could be used to bridge the energy and capacity need until a more permanent replacement is available. The Coalition, Joint Parties, and NWEC all argue for replacing Boardman with resources that are cleaner than a natural gas CCCT. PGE indicates that replacement with a greater mix of market purchases or renewable resources is either too risky or too costly.

[28] PGE's September 27, 2010 Comments at 6.
[29] PGE's September 27, 2010 Comments at 33.
[30] PGE's September 27, 2010 Comments at 7.

NIPPC recommends that the Commission require PGE to issue an RFI to potential suppliers of replacement power and file an IRP addendum that more fully addresses the replacement options. Both the Joint Parties and NWEC argue that more time is needed to develop and implement a replacement strategy. The Coalition recommends that we send PGE back to the drawing board.

The upshot of this debate is that it is uncertain whether a reasonable replacement strategy for Boardman can be developed and implemented by late 2015 or early 2016. We find it plausible that a combination of bridge PPAs and construction of a natural gas CCCT could replace Boardman in this timeframe without adverse impacts to ratepayers. We are skeptical, however, that Boardman can be replaced in this timeframe with bridge PPAs and a mix of cleaner resources without excessive risk and cost. This issue is best addressed in PGE's IRP Update and future competitive bidding proceedings.

We now turn to our acknowledgement decision.

PGE's IRP makes the case that if the proposed BART III compliance actions meet the Oregon Regional Haze Plan and Oregon Utility Mercury Rule standards, then this combination of pollution control investments and commitment to cease coal-fired operations at Boardman in 2020 provides the best combination of expected costs and risks for ratepayers. We acknowledge PGE's proposed BART III compliance actions for the Boardman plant.

PGE's BART III proposal is contingent on EQC approval. The acknowledgement of a backstop option would require us to predict or prejudge which compliance options might remain if the EQC denies PGE's BART III proposal. Several parties in this proceeding have pointed to the similarity between PGE's BART III proposal and DEQ's Option 2 and have predicted that if neither of these options is approved, the remaining choice would be between DEQ's Option 3 with shutdown by early 2016 and the original BART I with operation, if possible, through 2040. We do not accept this logic and decline to predict the EQC's actions.

Even if we were to accept this narrow logic, the uncertainty surrounding the feasibility of implementing a reasonable replacement strategy by late 2015 or early 2016 would be difficult to overcome. We would likely need additional information about the different replacement options before we could acknowledge a reasonable choice. The development and implementation of a reasonable replacement strategy is directly related to the choice of the fuel type of the replacement resources. All of the alternatives to BART III and DEQ Option 2 discussed in this case contain significant risks for ratepayers.

Because we decline to predict the EQC's upcoming decisions, we also decline to acknowledge any backstop option at this time. If the EQC denies PGE's BART III proposal, then PGE has the ability to present its next preferred option, and ask for Commission acknowledgment, in an IRP Update. We adopt Staff's recommendation to require PGE, in the event that the EQC declines accept PGE's BART III proposal, PGE must file a backstop proposal and supporting analysis in its next IRP Update.

> *In the event the EQC denies PGE's request to amend its Regional Haze Plan to facilitate PGE's BART III proposal, PGE must include in its next IRP Update an alternative preferred proposal and supporting analysis.*

Our decision does not mean that it would be imprudent for PGE to choose the BART I compliance actions if the only other available alternative is closure of Boardman in 2015 or early 2016. It simply means that we refuse to prejudge the EQC's actions. Analysis on the record in this case does indicate, however, that delaying shutdown of Boardman to allow for the development of a reasonable replacement strategy can provide significant protections for both ratepayers and the environment.[31]

Cascade crossing.

The Cascade Crossing Transmission Project (Cascade Crossing) is a proposed 500 kV transmission line connecting its Boardman and Coyote Springs plants to the southern portion of its service territory. The proposed project would begin at PGE's Coyote Springs substation, go to the Boardman plant and terminate at PGE's Bethel substation. The project would parallel existing utility lines for the first 106 miles from the Boardman substation toward Bethel, and parallel PGE's existing Bethel-to-Round Butte 230 kV line over the Cascades for the last 77 miles. The project will require the construction of a 500/230 kV substation, 500/230 kV transformer, and 500/230 kV transformer bank and improvements to two existing substations.[32]

PGE asserts that Cascade Crossing will (1) directly connect west-side load to existing and new resources on the east side of the Cascade; (2) add transfer capacity to the Cross-Cascades South and West of Slatt cutplanes; (3) reduce stress on the I-5 cutplanes by providing another path to its system from the south; (4) provide firm transmission service as an alternate to BPA service for existing generation; and (5) improve reliability by providing additional transmission and reducing load on transfer paths parallel to Cascade Crossing, reducing the severity of currently limiting contingencies.[33]

PGE seeks conditional acknowledgment to build Cascade Crossing as a double-circuit 500 kV and alternatively, as a single-circuit 500 kV. PGE states that whether it proceeds with Cascade Crossing, as either a double-circuit or single-circuit, will depend on future economic analysis incorporating refined cost estimates, updated information regarding

---

[31] We note that we declined to acknowledge PacifiCorp's request to develop two coal-fired resources and encouraged the company to delay an irreversible commitment to coal in Order 06-029. In this case, delaying the irreversible commitment to shutdown a coal plant could provide the time and flexibility needed to develop the best replacement resources.
[32] PGE IRP at 187.
[33] PGE IRP at 189-90.

path rating, the level of equity participation from third parties, transmission service requests received by PGE, and updated information regarding PGE's generation facilities that would utilize the project.

*Parties' positions***:** RNP believes Cascade Crossing will directly facilitate wind interconnections and will provide links between eastern Oregon wind, solar, and geothermal resources with western load centers. RNP supports acknowledgment of Cascade Crossing so long as it can be responsibly sited and developed within parameters of a sensible and timely cost-benefit analysis. RNP recommends that the Commission require PGE to update its analysis regarding Cascade Crossing in a future IRP or IRP update.[34]

CUB has the following questions and concerns regarding PGE's proposed Cascade Crossing Transmission Project, but does not go so far as to recommend against acknowledging the project: (1) Why does the expected closure of Boardman not affect PGE's plan for Cascade Crossing; (2) Why aren't BPA transmission services sufficient to serve PGE's needs; (3) Does PGE have sufficient experience to manage construction of Cascade Crossing without incurring significant cost overruns; (4) Should new transmission be a top priority for PGE?

Willard Rural Association (WRA) recommends that the Commission not acknowledge Cascade Crossing asserting that PGE overstates its load forecast, understates the amount of transmission BPA will have in the future and overstates the cost of that transmission, underestimates the cost to acquire right of way for Cascade Crossing and understates the risk associated with an $823 million investment.

Staff recommends that the Commission acknowledge Cascade Crossing in the double-circuit configuration, subject to the requirement that PGE provide the Commission certain information and updated analysis in its next IRP Update.

Staff asserts that PGE's proposal to acquire a transmission resource is supported by analysis under Guideline 8. Staff agrees with PGE's conclusions that adding transmission to PGE's system will allow additional purchases and sales, access to less costly resources in remote locations, access to renewable resources developed on the east side of the state, and will improve reliability.

Staff also asserts that PGE's financial and qualitative analysis (some done in response to a Staff data request) supports PGE's conditional proposal build Cascade Crossing, as opposed to acquiring transmission in another manner. Staff explains that PGE analyzed the "economic benefit" of Cascade Crossing, which PGE defines as the cost of utilizing BPA transmission service minus the cost of Cascade Crossing, for the top three preferred

[34] RNP Sept 1, 2010 Reply Comments at 3.

scenarios against five cases. The five cases utilize different assumptions for the growth rate of the BPA transmission tariff rate and the extent to which PGE may partner with other entities to build the project.

Staff concludes that PGE's analysis shows that Cascade Crossing is economic with relatively conservative estimates regarding BPA transmission rate increases, equity participation by third parties and requests for service by third parties.

Commission Resolution: Guideline 8 directs utilities to consider transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.[35] We agree with Staff's conclusion that PGE complied with this guideline, and with Staff's conclusion that the considerations of Guideline 8 support PGE's proposal to acquire additional transmission resources. We are not persuaded by WRA's assertion that there is no present need to build a transmission facility from the eastern part of the state to PGE's service territory. PGE's proposal to build Cascade Crossing does not turn on load growth expectations. Instead, PGE's proposal is based largely on other factors, including relieving transmission constraints in the northwest and accessing renewable generation in the eastern part of the state.

We also agree with Staff's conclusion that PGE's financial and qualitative analysis supports acknowledgment of PGE's conditional proposal build Cascade Crossing, as opposed to acquiring transmission in another manner. PGE's IRP analysis, based on conservative assumptions regarding BPA's transmission rates and available capacity, reflect that Cascade Crossing is economic, as compared to using BPA transmission service, if other milestones are reached, *e.g.,* equity partnership.

We do not agree with WRA's assertions regarding the cost and availability of BPA transmission or with WRA's assertions regarding costs to acquire right-of-way. We agree with Staff that BPA's economic analysis is based on conservative assumptions regarding BPA's future transmission rates. And, we are not persuaded by WRA's anecdotal evidence regarding the price paid for an easement in California several months prior to the start of the 2007-09 recession.[36]

We also find that contrary to WRA's assertion, PGE's estimated costs for Cascade Crossing include costs to upgrade PGE's existing 230-kilovolt (230-kV) transmission line from Salem to Oregon City. With respect to the upgrades to the Salem to Oregon City line, PGE's estimated costs include an estimate of approximately $47 million (2009$) for the Willamette Valley upgrade. This estimated cost includes the procurement and

---

[35] Order No. 07-002 at 11.
[36] *See* WRA Intervenor's Comments at 2-3.

construction costs for the structures and conductors and associated equipment to be built entirely within PGE's existing right-of-way for the Bethel to Monitor to McLoughlin 230 kV line, based on $1 million per mile plus the cost for terminating the new line in the Bethel and McCLoughlin substations.[37]

In any event, PGE has made clear that its decision to proceed with Cascade Crossing turns on future analysis, including analysis comparing the cost of using BPA transmission and third-party transmission instead of building Cascade Crossing. We will require PGE to present specific information in this analysis. WRA will have opportunity to advocate against acknowledgment of Cascade Crossing after PGE has completed the future analysis.

Finally, we do not share all CUB's concerns. We do think transmission is a top priority. And given that few transmission facilities have been constructed in the Northwest in recent history, we do not think that expertise in building transmission projects should be a necessary predicate for Cascade Crossing. With respect to CUB's inquiry about relying on BPA to serve PGE's transmission needs, we note that we have further opportunity to review whether BPA will have sufficient resources to serve PGE's needs prior to the time PGE proceeds with Cascade Crossing. And with respect to the uncertainty regarding Boardman, we are persuaded by PGE's arguments that Boardman's continued operation is not a necessary predicate for Cascade Crossing's construction.

We acknowledge PGE's conditional proposal for Cascade Crossing, subject to the following requirement:

> *PGE will include in its next IRP Update:*
>
> a. *An updated plan of service and project calendar or Cascade Crossing;*
>
> b. *Executed equity and capacity participation and interconnection agreements;*
>
> c. *Status of directional ratings on all circuits proposed;*
>
> d. *The same benefit-cost model PGE used in its IRP updated to contain then current inputs for Cascade Crossing and continued transmission service through BPA.*

We also adopt Staff's recommended requirement regarding future IRP analysis regarding transmission. Staff notes that PGE included little sensitivity analysis regarding Cascade Crossing in its IRP. We agree with Staff that sensitivity analysis is an integral part of integrated resource planning and will require PGE to include such analysis in all future IRPs.

---

[37] PGE Sept 27, 2010 Reply to Intervenor Comments at 11-12.

We also adopt Staff's recommendation that we require PGE include analysis regarding upgrades to facilities used for transmission between Oregon City and PGE's Bethel Substation.

PGE will include in its next IRP:

a. An evaluation of potential transmission reinforcement between Salem and Oregon City areas with alternative northern endpoint areas, with and without equity partners.

b. Sensitivity analysis around financial and factual assumptions underlying transmission decisions.

Load forecast

Parties' positions: As discussed in the section regarding Boardman above, many parties take issue with PGE's load forecast. Parties believe that PGE failed to adequately account for lingering effects of the 2007-09 recession and conservation. In addition, Staff believes that PGE should perform a more robust analysis regarding potential load loss due to distributed and self generation. We agree with Staff's assessment that PGE's load forecast provides a reasonable basis for PGE's portfolio selection. Nonetheless, we will require PGE to update its load forecast in its next IRP Update and to provide the analysis recommended by Staff:

PGE must update its load forecast in PGE's next IRP Update.

In the next planning cycle, PGE must analyze the extent of potential load loss due to distributed and self generation.

Natural gas price forecast method

Parties' positions: Staff takes issue with PGE's reliance on single sources for fundamental long-term natural gas price forecasts and short-term price indicators. Staff notes that by relying on only the PIRA Energy Group for long-term gas price forecasts, PGE has failed to ameliorate any bias that PIRA has. The same is true of PGE's reliance on only one source, New York Mercantile Exchange (NYMEX), for short-term price indicators. However, Staff's concern regarding NYMEX is also based on the fact NYMEX is not a forecasting service.

Commission resolution: We agree with Staff's concern regarding the increased potential for bias in natural gas price forecasts and short-term price indicators that will result from reliance on single sources. We encourage PGE to rely on multiple sources for its natural gas price forecasts in future IRP Updates and IRPs.

Demand response

Parties' positions: Pareto Energy generally supports PGE's initial conclusions and recommendations in PGE's IRP. Pareto Energy asserts that advances in technology, laws and regulation and project financing options for distributed energy resources (DER) warrant contingency planning in the IRP in the event of large-scale adoption of DER by PGE's customers.[38]

Staff concludes that PGE did not comply with Guideline 7 regarding demand response (DR) because PGE failed to evaluate DR on par with other options for meeting energy, capacity, and transmission needs. Staff recommends that we require PGE to include certain information in its analysis to do this comparison, and that PGE comply with Guideline 7 in PGE's next IRP Update.

Commission resolution: We agree with Staff that PGE must include additional information in its analysis to allow PGE to evaluate DR on par with other resources. In addition to being required by Guideline 7, a consistent method for evaluation of all resources is a substantive requirement of integrated resource planning under Guideline 1. Accordingly, we order PGE to comply with Guideline 7 in PGE's next IRP Update by including the information specified by Staff in its Final Comments.

> *In its next IRP Update, PGE must meet Guideline 7 in its entirety, and therefore must provide the following information to allow comparison of DR on par with other options for meeting energy, capacity, and transmission needs:*
>
> *a. MW projections of capacity "contributions" by year and by DR class (e.g., Class 1 is directly dispatchable load curtailment; Class 2 DR relates to dynamic price signals and customer responsiveness thereto); and*
>
> *b. Projected cost per MW of capacity savings by DR type.*

We do not adopt Pareto Energy's recommendation to include contingency planning in its IRP in the event of large-scale adoption of DR. Utilities are required to file IRPs every two years and in between these filings, file IRP Updates. The frequency of these filings allows utilities sufficient opportunity to analyze signals regarding adoption DR and plan appropriately.

Energy Efficiency

Parties' positions: Staff believes that PGE complied with three of four requirements in Guideline 6. Guideline 6 requires utilities to (1) ensure that a conservation potential

[38] Pareto Sept 1, 2010 Reply Comments at 1.

study is conducted periodically for its entire service territory; (2) to the extent the utility control the level of funding for conservation programs in its service territory, the utility should include in its 3) determine the amount of conservation resources in the best cost/risk portfolio without regarding to funding limits; and 4) identify the preferred portfolio and action plan consistent with third-party's projection of conservation acquisition.

The Energy Trust of Oregon (ETO) performed the assessment required under Guideline 6.a. and PGE complied with the requirements of Guideline 6.c. with respect to conservation programs administered by the ETO. Staff does not think PGE complied with Guideline 6.b.

Staff reports that the ETO's assessment identified the technical potential for 19 MWa of conservation voltage reduction in PGE's service territory for the period 2008-27. Conservation voltage reduction is not conservation administered by the ETO. Instead, it is a conservation measure implemented by the utility in the utility's distribution system. Staff notes that PGE's IRP does not show that PGE included conservation voltage reduction as a potential resource or analyzed whether it should be included in PGE's action plan.

Commission resolution: We agree with Staff's conclusions that PGE complied with Guideline 6.a. and 6.c., but failed to comply with 6.b. We are puzzled as to why PGE overlooked conservation voltage reduction in its analysis of available resources and order PGE to complete the analysis required by Guideline 6.b. for this resource in PGE's next IRP Update.

> *In its next IRP Update and in the next planning cycle, PGE must evaluate the potential for Conservation Voltage Reduction*.

RPS Requirements

Parties' positions: PGE proposes to acquire 122 MWa of renewable wind generation by the end of 2012 to achieve physical compliance with the (RPS) Requirement for 2015. PGE asserts that banking renewable energy credits (RECs) from early renewable resource actions provides a significant cushion for "meeting RPS compliance."[39]

Staff is concerned that PGE did not model the use of unbundled RECs to comply with the RPS Requirements for the entire planning period. Staff notes that PGE's analysis is predicated on an assumption that PGE would comply with the RPS Requirement with physical resources, rather than unbundled RECs. Staff recommends that the Commission require to PGE "relax" the assumption that PGE must be in physical compliance with the

[39] PGE IRP at 114.

2015 RPS Requirement. In other words, Staff recommends that PGE's analysis include the possibility that PGE will use unbundled RECs to comply with the 2015 RPS Requirement.

In support of this recommendation, Staff notes that several factors could result in a situation in which it is more cost effective to acquire physical resources later, rather than sooner, *e.g.*, due to emerging technology. Staff also notes that PGE's concerns regarding penalties for non-compliance appear to be overstated.

The Oregon Department of Energy (ODOE) notes that PGE's plan for physical RPS compliance overbuilds in the near term. ODOE finds the plan appropriate where short-term REC sales provide value to current utility customers at the same time prudent banking reduces RPS compliance risk beyond 2020. ODOE notes, however, that PGE should address the substantial REC output to be made available in 2011 due to the passage of HB 3674 (2010). ODOE reports that the bill makes a number of pre-1995 biomass facilities eligible for the RPS with the condition that REC output from those facilities cannot be used until 2026. ODOE notes that these facilities are expected to produce over 7 million RECs.[40]

ODOE also notes that PGE's IRP contains an incorrect conclusion regarding the penalty risk associated with failure to meet the RPS Requirement. ODOE notes that the Alternative Compliance Payment is not a direct penalty as the RPS allows a variety of paths for a utility to invest those payments toward future project development.[41]

Commission resolution: We see no reason that PGE's analysis of the least cost and least risk method to comply with RPS Requirements should exclude the possibility of using unbundled RECs to meet RPS Requirements at any point in the planning period, including the early years. Both Staff and ODOE identify circumstances that could lead to the conclusion that relying on unbundled RECs in early years of the planning period could be least cost and least risk.

> *In its next IRP Update and in the next planning cycle, PGE must evaluate the use of unbundled RECs in its strategy to meet RPS Requirements for the entire planning period.*
>
> *In its next IRP Update and in the next planning cycle, PGE must evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.*

[40] ODOE May 14, 2010 Comments at 3.
[41] ODOE May 14, 2010 Comments at 4.

Wind integration study

Parties' positions: RNP recommends that the Commission not acknowledge PGE's wind integration study on which PGE based its analysis of the cost to operate and acquire wind generation. RNP asserts that PGE's wind integration costs include an unusually cost of reserves and that that stakeholders and the Commission cannot evaluate the reasonableness of PGE's costs because PGE based them on an analysis that has not been unveiled.[42] RNP recommends that the Commission order PGE to continue to use the BPA wind integration rate to model new wind resources until such time as PGE is prepared to fully engage with stakeholders in review of its methodology and results.

Staff also asserts that PGE did not comply with the Commission's order stemming from PGE's last IRP to "include in the [next IRP] analysis a wind integration study that has been vetted by regional stakeholders."[43] Staff echoes RNP's statements that PGE has not produced a study whose detailed methodology and results have been made available for review.

PGE disputes RNP's and Staff's characterization of the wind integration study process. PGE states that it engaged a Technical Review Committee consisting of several stakeholders to evaluate its study approach, inputs and findings, and on September 19, 2009, conducted a three-hour workshop to present the details of its wind integration study.

PGE also disputes RNP's assertion that the wind integration costs underlying PGE's IRP analysis are unreasonably high. PGE notes that RNP's assertions are largely based on comparisons to other utilities' costs and to BPA's Balancing Authority within-hour integration tariff. PGE notes that these comparisons are inappropriate because each utility's costs depend on the unique characteristics of the utility's system and PGE's wind integration costs is comprised of several components, only of which is comparable to the within-hour integration tariff.[44]

Commission resolution: We agree with Staff and RNP that PGE did not comply with our order to include in its IRP analysis a wind integration study that has been vetted by stakeholders. As PGE itself acknowledges, the stakeholder "vetting" consisted of preliminary input from a technical group and a workshop. PGE's presentation at the workshop reflects that PGE informed stakeholders how it intended to go about the study. As RNP and Staff note, such a presentation is not a substitute for allowing stakeholders to evaluate the methodology that PGE actually used and its results. Accordingly, we will

[42] RNP Sept 1, 2010 Reply Comments 1-3.
[43] OPUC Order No. 08-246 at 10.
[44] PGE Sept 27, 2010 Reply to Intervenor Response Comments at 18.

once again impose a requirement that PGE prepare a wind integration study and allow stakeholders an opportunity to vet it:

> *In its next IRP Update and in the next IRP planning cycle, PGE must include a wind integration study that has been vetted by regional stakeholders.*

We do not adopt RNP's to direct PGE to use BPA's wind integration rate to model new resources. To the extent that RNP believes PGE's selection of portfolios is suspect because of underlying assumptions, RNP is free to advocate for a different portfolio selection.

Risk metrics

Parties' positions: Staff notes its concern with two of PGE's metrics used to measure overall risk, referring to them as "Average of Worst Four Futures Less the Reference Case Costs"[45] and "TailVar90 Less the Mean." Staff explains that both measures subtract the mean or reference case value from extreme or bad values obtained by determining the "average of worst four futures," or the average of the ten highest cost outcomes as measured in the TailVar90 metric. Staff notes subtracting the reference or mean case values may result in portfolios with bad (*i.e.* high) "worst four" or TailVar90 metrics, nevertheless registering a good (*i.e.* low) overall risk score because the mean or reference case value that is subtracted is also bad (*i.e.*, high).

RNP and NWEC take issue with these two risk metrics, as well. NWEC asserts that these risk metrics are measures of spread or variability, not measures of risk of bad outcomes. NWEC argues that "any metrics such as these that subtracts out the mean, in cases where the mean can be very different across tested portfolios, is faulty, since high variability in itself is not a bad outcome."[46] RNP asserts the metrics do not measure relevant risks.[47]

RNP and NWEC also take issue with PGE's "Year-to-Year Variation" risk measure.[48] NWEC explains that using year-to-year variation as a risk measure is probative of little because variation does not necessarily indicate poor performance. RNP asserts this metric fails to measure relevant risk.[49]

Based on its concerns with the three risk metrics discussed above, as well as absence of what RNP believes would be pertinent risk metrics such as a carbon emission factor, RNP recommends that the Commission require PGE to revise its methodology in future IRPs to appropriately reflect relevant risk factors, dropping duplicative or irrelevant

---

[45] PGE also refers to this metric as the "Deterministic Portfolio Risk Variability vs. Reference Case." *See* PGE IRP at 249.
[46] NWEC May 14, 2010 Comments at 13.
[47] RNP May 20, 2010 Comments at 3.
[48] RNP May 20, 2010 Comments at 3.
[49] RNP May 20, 2010 Comments at 3.

metrics and adding a risk metric proportional to emissions of pollutants, including carbon dioxide.[50]

NWEC urges the Commission to direct PGE to improve future IRPs to correct the flaws in its risk analysis, along with other flaws discussed in NWEC's comments. [51]

In response to NWEC' and RNP's criticisms, PGE asserts that the TailVar90 Less Mean and Average of Worst Four Futures Less Reference Case Costs are required by Guideline 1.c., which requires plans to "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."[52] With respect to the Year-to-Year Variance Metric, PGE asserts it is necessary to measure variance risk because rate stability is important to customers.[53]

Commission resolution: We agree with Staff, RNP, and NWEC that PGE's "Average of Worst Four Futures Less Reference Case Costs," and "TailVar90 Less Mean" metrics can be misleading. Subtracting the mean or reference case from the calculations required by the IRP Guidelines can distort the results of these required metrics. We note, however, that PGE did calculate the more conventional metrics, as suggested by Staff, and that PGE factored those measures into its analysis.

We do not share RNP's and NWEC's concerns regarding the year-to-year variability metric. We agree that it is appropriate to measure variance and variability risk.

We decline to order PGE to improve its methodology, as requested by NWEC. PGE must comply with the IRP Guidelines. It is within PGE's discretion to perform analysis not required by the Guidelines. Generally, we encourage utilities to provide more, rather than less, analysis. However, we will likely give little weight to analysis that is potentially misleading or not probative.

Reliability

Parties' positions: NWEC comments that PGE's reliability metric based on the expected unserved energy value for each portfolio measures exposure to market and is independent of PGE's portfolios; meaning it is a measure of how "long" a portfolio is, not the nature of the portfolio. NWEC notes that because it is an independent factor, it can be increased or decreased for any portfolio by adding a relatively small amount of extra capacity. NWEC asserts that the reliability metric should not be used to judge a particular portfolio. [54]

[50] RNP May 20, 2010 Comments at 3.
[51] NWEC May 14, 2010 Comments at 14.
[52] PGE Aug 10, 2010 Reply Comments at 46.
[53] PGE Aug 10, 2010 Reply Comments at 47.
[54] NWEC Sept 1, 2010 Reply Comments at 6-8.

Staff agrees with NWEC that PGE's conditional expected unserved energy (EUE) metric is a market exposure metric and not a valid reliability metric. Staff notes that a portfolio can get a low conditional EUE score, but due to having a very high, but unrecognized LOLP, get a high (*i.e.,* bad) "energy not served" (ENS) score. In other words, a particular portfolio may suffer from many hours of outages, (*i.e*., have a very high LOLP), but due to a low amount of compensatory spot market purchases per lost load hour, that portfolio would undeservedly (since the unreported, UEU score would be high), get a favorable CEUE score.

PGE denies NWEC's assertion that PGE's reliability metric is independent of the IRP portfolios. PGE asserts that the "reliability metric instead addresses the relative reliability of the portfolios based on the particular resources in them, with their assumed associated forced outage rates and mean times to repair.[55]

Commission resolution: We share NWEC's and Staff's concerns regarding PGE's conditional EUE metric. We conclude that PGE's calculation of *conditional* EUE is not sufficient to comply with Guideline 11. We require PGE, in its next IRP Update, to comply with Guideline 11 by performing *all* the analyses required by that guideline, including a determination of "Expected and Worst-Case Unserved Energy":

> *In its next IRP Update and all subsequent IRPs, PGE must fully comply with all requirements of Guideline 11.*

Although we share the concerns of Staff and NWEC regarding the potentially misleading nature of PGE's conditional EUE determination, we do not order that PGE refrain from providing this calculation in future IRPs. PGE may choose to perform this calculation in addition to the calculation of EUE. But for the reasons advanced by Staff and NWEC, we are not likely to rely on it.

III. CONCLUSION

PGE's 2009 IRP reasonably adheres to the principles of resource planning established in Order No. 07-002 and is conditionally acknowledged with the following requirements:

> *In the event the EQC denies PGE's request to amend its Regional Haze Plan to facilitate PGE's BART III proposal, PGE must include in its next IRP Update an alternative preferred proposal and supporting analysis.*

> *PGE will include in its next IRP Update:*

[55] PGE Reply to Intervenor Comments at 34, *citing* PGE IRP at 245-47.

a. An updated plan of service and project calendar or Cascade Crossing;

b. Status of equity and capacity participation and interconnection agreements;

c. Status of directional ratings on all circuits proposed;

d. The same benefit-cost model PGE used in its IRP updated to contain then current inputs for Cascade Crossing and continued transmission service from BPA.

PGE will include in its next IRP:

a. An evaluation of potential transmission reinforcement between Salem and Oregon City areas with alternative northern endpoints, with and without equity partners.

b. Sensitivity analysis around financial and factual assumptions underlying transmission decisions.

c. PGE must update its load forecast in PGE's next IRP Update.

In the next planning cycle, PGE must analyze the extent of potential load loss due to distributed and self generation.

In its next IRP Update, PGE must meet Guideline 7 in its entirety, and therefore must provide the following information to allow comparison of DR on par with other options for meeting energy, capacity, and transmission needs:

a. MW projections of capacity "contributions" by year and by DR class (e.g., Class 1 is directly dispatchable load curtailment; Class 2 DR relates to dynamic price signals and customer responsiveness thereto); and

b. Projected cost per MW of capacity savings by DR type.

In its next IRP Update and in the next planning cycle, PGE must evaluate the potential for Conservation Voltage Reduction.

In its next IRP update and in the next planning cycle, PGE must evaluate the use of unbundled RECs in its strategy to meet RPS Requirements for the entire planning period.

In its next IRP update and in the next planning cycle, PGE must evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/ least risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources.

In its next IRP Update and in the next IRP planning cycle, PGE must include a wind integration study that has been vetted by regional stakeholders.

In its next IRP Update and all subsequent IRPs, PGE must comply with all requirements of Guideline 11.

Effect of acknowledgement 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[.]
>
> Acknowledgement 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.[56]

[56] Order No. 89-507 at 6 and ll.

Appendix A: Adherence to the Plan to Integrated Resource Planning Guidelines

In considering whether to acknowledge a resource plan, the Commission reviews the plan for adherence to our Guidelines for resource planning. We address each of the Guidelines separately below. A complete copy of the Guidelines can be found in Commission Order No. 07-002 and Order No. 08-339.

Guideline 1: Substantive Requirements

Under Guideline 1, an electric utility should:

a. Evaluate all resources on a consistent and comparable basis,
b. Consider risk and uncertainty,
c. Select a portfolio with the best combination of expected costs and associated risks and uncertainty for the utility and its customers, and,
d. Be consistent with the long-run public interests as expressed in Oregon and federal energy policies.

Staff finds that the Company met this requirement. Portland General Electric (PGE) considered all known supply-side and demand-side resources that are expected to become available when preparing its 2009 IRP. PGE's current supply portfolio is a diverse mix of generating resources that includes hydropower, coal and natural gas combustion, and wind resources. In its 2009 IRP, PGE modeled solar, nuclear, wave, integrated gasification combined cycle (IGCC) coal, wind, combined cycle combustion turbines (CCCT), combined heat and power (CHP), biomass and geothermal in conjunction with energy efficiency (EE).

PGE used net present value of revenue requirements (NPVRR) to assess the expected cost of portfolios. They also utilize a variety of deterministic, stochastic, reliability and diversity metrics to examine the various risk and durability aspects of each portfolio. In its evaluation, the Company considered the following sources of risk and uncertainty: volatile behavior for natural gas prices, weather impact to loads, water years, wind intermittency and plant forced outages with mean time to repair. For greenhouse gas emissions the Company modeled a 2020 Oregon CO_2 Goal portfolio. These assessments provide a consistent basis for evaluating portfolios.

Guideline 2: Procedural Requirements

Guideline 2 is a description of procedural requirements that require a utility to include the public as well as other utilities in the IRP planning process. PGE met all procedural requirements. The Company provided multiple opportunities for public input throughout the IRP process.

As part of the IRP process, PGE solicited input from various stakeholder groups. PGE held public meetings, directed outreach activities to customers and participated in state and regional planning efforts. PGE published all non-confidential presentation material from public meetings and workshops on the Company website, in handouts, technical appendices and in response to data requests.

Guideline 3: Plan Filing, Review, and Updates

Guideline 3 states that a utility must file its IRP two years from the date of acknowledgement of the previous plan. PGE filed their 2007 IRP in June 2007. On May 6, 2008 the Commission declined to acknowledge the 2007 IRP and directed the Company to submit a new IRP within 18 months or by November 5, 2009. PGE's 2009 IRP was filed November 5, 2009. January 14, 2010 the Company issued a request to delay filing the first Boardman Alternative. The first Boardman Alternative was filed as an addendum on April 9, 2010 and April 26, PGE presented the 2009 IRP to the Commission at a public meeting. Throughout the IRP process the Company continued to hold public meetings and technical workshops as more alternatives and options were identified.

Guideline 4: Plan Components

Guideline 4 requires a utility to include fourteen components in its IRP evaluation. PGE has met this requirement. In the Company's IRP Appendix A – Compliance with Order No. 07-002 PGE provided a side-by-side comparison of how each of the substantive and procedural requirements were met.

PGE updated its long-term system load forecast in March 2009. For IRP purposes, PGE identified annual energy needs under their reference case and high-load and low-load forecasts. PGE's reference case load growth forecast indicates a long-term load growth of 2.2% for the period 2010 – 2030. The Company is forecasting a capacity need of 1,505 MW in 2013 and an average energy need of 751 MWa in 2015. Chapter 3 – Resource Requirements is a detailed write up of the Company's load forecasting and analysis.

As with their previous IRP, PGE used AURORAxmp® by EPIS, Inc. to assess Western electricity supply and demand as well as resource dispatch costs and resulting market prices on an hourly basis for the entire WECC region across their planning horizon. For more detail regarding PGE's modeling process and results see Chapters 10 and 11.

Demand-side and supply-side resources have been evaluated by the Company in the 2009 IRP. Since the last IRP, PGE has been actively working with the Energy Trust of Oregon (ETO) to promote EE, overcome EE market barriers, test new EE markets, and pre-qualify customers for existing ETO programs. In addition to analyzing energy supply-side alternatives that are currently available, PGE also reviewed developing technologies such as high altitude wind and in-stream hydrokinetics for inclusion in future IRPs. Chapters 4 and 7 respectively provide detail regarding PGE's approach on energy efficiency and demand side management and their analysis of supply side alternatives.

In its IRP, the Company details the proposed action plan in Chapter 13 – PGE Recommended Action Plans. There are several actions early on in the plan the Company intends to undertake or commit to in the next two to four years for resource additions that are targeted to be online by 2015.

Guideline 5: Transmission

Guideline 5 requires the Company to consider transmission as a resource option, taking into consideration its value for making additional purchases and sales, accessing less costly resources in remote locations, and improving reliability. PGE has met this requirement.

In its 2009 IRP, the Company evaluates two transmission builds and acquisition of additional pipeline capacity to support additional gas generation. For transmission builds, PGE is requesting Commission acknowledgment of the Cascade Crossing Transmission Project. The Company compares the economic benefit and cost of Cascade Crossing versus increased utilization of Bonneville Power Administration (BPA) transmission service. PGE also separately evaluated the performance of Cascade Crossing against the top-performing portfolios. For all transmission builds in the 2009 IRP, Company compares the proposed builds to proxy transmission resources.

For further detail of PGE's analysis of the Cascade Crossing Transmission Project see Staff's comments or Chapter 8 – Transmission of the IRP.

Guideline 6: Conservation

Guideline 6 requires a utility to perform a conservation potential study periodically for its entire service territory. In addition, the Company should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets. PGE has met this requirement.

Senate Bill 1149 consolidated funding for EE at the state level by directing funds collected from utility customers through a 3% public purpose charge to several agencies charged with responsibility for running EE programs, primarily the Energy Trust of Oregon. For the past six years PGE has successfully worked with the ETO and utility customers to implement EE measures. In its 2009 IRP, the Company includes a study conducted by the ETO of technical and achievable potential energy efficiency. The study can be found in Chapter 4 – Demand Side Options.

In determining the amount of conservation resources in the best cost/risk portfolio, PGE bases their selection on studies conducted by the ETO which determine the amount of potential EE without regard to any funding limits.

The Company's preferred portfolio and action plan are consistent with the ETO's projection of energy efficiency potential.

Guideline 7: Demand Response

Guideline 7 states that a utility should evaluate demand response resources including voluntary rate programs on par with other options for meeting energy, capacity and transmission needs.

PGE has not met this requirement. When evaluating projected cost per MW of capacity savings by demand response (DR) type, the Company did not incorporate per-MW unit costs in its DR analyses. In general the Company seems to lag in its analyses of the costs of implementing various DR options, and how far and fast the Company should go in pursuing them.

Guideline 8: Environmental Costs

Guideline 8, as modified by Order No. 08-339, contains four requirements: a base case scenario, alternative portfolios against the base case scenarios, a trigger point analysis, and an Oregon compliance portfolio. The first requirement directs the Company to model what it considers to be the most likely regulatory compliance future for greenhouse gas emissions, as well as other possible credible scenarios. The second requirement discusses the treatment of these scenarios in its risk-analysis, PVRR cost and risk measures and end-effect considerations. The third requirement directs the utility to identify a carbon dioxide compliance scenario that would lead to the selection of a portfolio that is substantially different from the preferred portfolio. The final requirement discusses the need for a separate portfolio, consistent with Oregon energy policies, if none of the previous portfolios achieves that consistency.

PGE met this requirement. In its IRP, PGE constructed a reference case based on third-party analysis of federal legislative CO_2 proposals with upper and lower bounds and a year-to-year shape. Several assumptions are made in the reference case, some of which are; compliance in the form of CO_2 price, emissions regulated at the point of combustion and implementation of emission controls at Boardman.

In identifying a trigger point, PGE tested CO_2 pricing which could trigger the selection from their preferred portfolio to a substantially different alternative portfolio, and found that the trigger point CO_2 price is $42 per short ton. PGE felt that because their preferred portfolio did not have new coal, no trigger point between coal and gas was needed. For more detail regarding CO_2 analysis see Chapter 11 – Modeling Results.

Guideline 9: Direct Access Load

Guideline 9 recommends that an electric utility exclude from their load-resource balance customer loads that are effectively committed to service by an alternative electricity supplier. PGE met this requirement.

Three and five-year opt-out load reached just over 190 MWa in 2008 and 2009.

Opt-out/opt-in election decisions magnify future load uncertainties and the related risk of having to procure or sell electricity in an adverse market. To address the uncertainties, PGE proposes the following planning approach. In accordance with Guideline 9, PGE will not plan energy resources for five-year opt-out customers (about 30 MWa at the time of analysis). For shorter-term opt-out eligible load the Company suggests a balanced approach that will avoid being overly short during times when more customers choose utility cost of service tariff offerings or being overly long during times of increased opt-out elections by PGE customers.

Guideline 10: Multi-state Utilities

Guideline 10 does not apply to Portland General Electric at this time.

Guideline 11: Reliability

Under Guideline 11, an electric utility 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-cast unsereved energy by year, and
c. Demonstrate that the selected portfolio achieves the utility's state reliability, risk and cost objectives.

PGE has not met this requirement. LOLP estimates were calculated, however; they did not appear among the cost and risk metrics used to score the competing portfolios. The Company calculated a conditional expected unserved energy value for each portfolio, but such does not appear among the cost and risk metrics used to score the competing portfolios. Staff recommends substituting LOLP as calculated by PGE, annual energy not served (ENS) as calculated by PacifiCorp and the average of the ten worst annual ENS's that are drawn from each portfolio's 100 stochastic risk iterations each weighted at five percent for PGE's 15 percent-weighted "worst-case unserved energy".

Guideline 12: Distributed Generation

Guideline 12 recommends that utilities evaluate distributed generation technologies on par with other supply-side resources. PGE has met this requirement.

Within PGE's service area, PGE engages in three main types of distributed generation (DG); dispatchable standby generation program (DSG), combined heat and power/CHP and solar photovoltaic (solar PV). PGE models all three types of DG in conjunction with central-station generation in most the portfolios modeled, including all of the top performing portfolios. PGE's proposed Action Plan recommends ongoing acquisition of DG.

In the Company's 2009 IRP Capacity Action Plan, PGE assumes they can achieve 67 MW (including 15 MW from the 2007 IRP) of additional dispatchable standby generation by 2013, for a total of 120 MW. The Company also assumes that 5 MWa of CHP will be acquired and between 4 and 12 MWa of distributed solar PV will be added. PGE plans to develop an additional 15 MW (almost 2 MWa) of customer-sited distributed solar generation by 2012.

Guideline 13: Resource Acquisition

Guideline 13 establishes requirements for acquiring resource in the utility's action plan. PGE has met this requirement.

PGE plans to develop and submit for consideration three new facilities (the "benchmarking resources") for the purpose of comparing with and evaluating against the responses to energy and capacity request for proposals the Company plans to issue pursuant to the 2009 IRP.

The three proposed benchmark resources are; two natural gas fired resources and one wind resource. The two natural gas fired resources are Port Westward Unit 2 and Carty Generation Station. The proposed Port Westward II is a 200 MW flexible capacity resource located at the Company's existing Port Westward Generation Project site. The proposed Carty Generation Station is a CCCT energy resource with nominal capacity in the 300 – 500 MW range, located near the Company's Boardman Coal Plant. The last proposed benchmark resource is a wind resource used to fill part of the Company's overall energy need and to help meet the Oregon 2015 RPS target. The wind resource would be sized in the 330 – 385 MW range, sited in Sherman, Jefferson or Umatilla counties and on line on or before December 31, 2014.

Chapter 9 – Benchmark Resource of the Company's 2009 IRP includes an assessment of the advantages and disadvantages of owning a resource instead or purchasing power from another party.

CERTIFICATE OF SERVICE

LC 48
Comments

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 15th day of October, 2010.

Kay Barnes

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

LC 48
Service List (Parties)

BRUCE A KASER	PO BOX 958 SILVERTON OR 97381-0958 brucekaser@comcast.net
KELLY NOKES	crk@gorge.net
JOHN PRESCOTT POWER RESOURCES COOPERATIVE	711 NE HALSEY PORTLAND OR 97232 jprescott@pngcpower.com
RYAN M SWINBURNSON COUNSEL FOR MORROW COUNTY	515 N NEEL ST KENNEWICK WA 99336 r_swinburnson@verizon.net
***DEPARTMENT OF JUSTICE**	
JANET L PREWITT **(C)** ASSISTANT AG	NATURAL RESOURCES SECTION 1162 COURT ST NE SALEM OR 97301-4096 janet.prewitt@doj.state.or.us
***OREGON DEPARTMENT OF ENERGY**	
KIP PHEIL **(C)** SENIOR POLICY ANALYST	625 MARION ST NE - STE 1 SALEM OR 97301-3737 kip.pheil@state.or.us
VIJAY A SATYAL **(C)** SENIOR POLICY ANALYST	625 MARION ST NE SALEM OR 97301 vijay.a.satyal@state.or.us
ANDREA F SIMMONS **(C)**	625 MARION ST NE SALEM OR 97301-3737 andrea.f.simmons@state.or.us
ASSOCIATED OREGON INDUSTRIES	
JOHN LEDGER	1149 COURT ST NE SALEM OR 97301 johnledger@aoi.org
ASSOCIATION OF OREGON COUNTIES	
PAUL SNIDER	PO BOX 12729 SALEM OR 97309 psnider@aocweb.org
BOMA PORTLAND	
SUSAN STEWARD EXECUTIVE DIRECTOR	200 SW MARKET, SUITE 1710 PORTLAND OR 97201 susan@bomaportland.org

CABLE HUSTON BENEDICT ET AL	
J LAURENCE CABLE **(C)**	1001 SW 5TH AVE STE 2000 PORTLAND OR 97204-1136 lcable@cablehuston.com
CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP	
RICHARD LORENZ **(C)**	1001 SW FIFTH AVE - STE 2000 PORTLAND OR 97204-1136 rlorenz@cablehuston.com
CITIZENS' UTILITY BOARD OF OREGON	
GORDON FEIGHNER **(C)** ENERGY ANALYST	610 SW BROADWAY, STE 400 PORTLAND OR 97205 gordon@oregoncub.org
ROBERT JENKS **(C)** EXECUTIVE DIRECTOR	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
G. CATRIONA MCCRACKEN **(C)** LEGAL COUNSEL/STAFF ATTY	610 SW BROADWAY, STE 400 PORTLAND OR 97205 catriona@oregoncub.org
CITY OF PORTLAND - CITY ATTORNEY'S OFFICE	
BENJAMIN WALTERS **(C)** CHIEF DEPUTY CITY ATTORNEY	1221 SW 4TH AVE - RM 430 PORTLAND OR 97204 ben.walters@portlandoregon.gov
CITY OF PORTLAND - PLANNING & SUSTAINABILITY	
MICHAEL ARMSTRONG **(C)** SUSTAINABILITY MANAGER	1900 SW 4TH AVE, STE 7100 PORTLAND OR 97201 michael.armstrong@portlandoregon.gov
DAVID TOOZE **(C)** SENIOR ENERGY SPECIALIST	1900 SW 4TH STE 7100 PORTLAND OR 97201 david.tooze@portlandoregon.gov
CLACKAMAS COUNTY BUSINESS ALLIANCE	
BURTON WEAST EXECUTIVE DIRECTOR	300 OSWEGO POINTE DR, STE 220 LAKE OSWEGO OR 97034 burton@ccba.biz
COLUMBIA CORRIDOR ASSOCIATION	
CORKY COLLIER	PO BOX 55651 PORTLAND OR 97238 corky@columbiacorridor.org

COLUMBIA RIVERKEEPER LAUREN GOLDBERG **(C)**	 724 OAK STREET HOOD RIVER OR 97031 lauren@columbiariverkeeper.org
COMMUNITY ACTION PARTNERSHIP OF OREGON JESS KINCAID ENERGY PARTNERSHIP COORDINATOR	 PO BOX 7964 SALEM OR 97301 jess@caporegon.org
DAVIS WRIGHT TREMAINE LLP JOHN DILORENZO	 1300 SW FIFTH AVE, STE 2300 PORTLAND OR 97201 johndilorenzo@dwt.com
MARK P TRINCHERO	1300 SW FIFTH AVE STE 2300 PORTLAND OR 97201-5682 marktrinchero@dwt.com
DAVISON VAN CLEVE IRION A SANGER **(C)** ASSOCIATE ATTORNEY	 333 SW TAYLOR - STE 400 PORTLAND OR 97204 ias@dvclaw.com
DEPARTMENT OF JUSTICE STEPHANIE S ANDRUS **(C)** ASSISTANT ATTORNEY GENERAL	 BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
ECUMENICAL MINISTRIES OF OREGON JAMES EDELSON	 415 NE MIRIMAR PL PORTLAND OR 97232 edelson8@comcast.net
ECUMENICAL MINISTRIES OF OREGON JENNY HOLMES ENVIRONMENTAL MINISTRIES DIRECTOR	 0245 SW BANCROFT, SUITE B PORTLAND OR 97239 jholmes@emoregon.org
ESLER STEPHENS & BUCKLEY JOHN W STEPHENS **(C)**	 888 SW FIFTH AVE STE 700 PORTLAND OR 97204-2021 stephens@eslerstephens.com; mec@eslerstephens.com
FRIENDS OF COLUMBIA GORGE MICHAEL LANG **(C)**	 522 SW FIFTH AVENUE, SUITE 720 PORTLAND OR 97204 michael@gorgefriends.org

IBERDROLA RENEWABLES, INC	
KEVIN LYNCH	1125 NW COUCH ST STE 700 PORTLAND OR 97209 kevin.lynch@iberdrolausa.com
TOAN-HAO NGUYEN	1125 NW COUCH ST PORTLAND OR 97209 toan.nguyen@iberdrolausa.com
IBEW LOCAL 125	
MARCY PUTMAN POLITICAL AFFAIRS & REPRESENTATIVE	17200 NE SACRAMENTO STREET PORTLAND OR 97230 marcy@ibew125.com
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES	
MICHAEL EARLY EXECUTIVE DIRECTOR	1300 SW 5TH AVE, STE 1750 PORTLAND OR 97204-2446 mearly@icnu.org
NORTHWEST ENERGY COALITION	
STEVEN WEISS SR POLICY ASSOCIATE	4422 OREGON TRAIL CT NE SALEM OR 97305 steve@nwenergy.org
NORTHWEST ENVIRONMENTAL DEFENSE CENTER	
MARK RISKEDAHL	10015 SW TERWILLIGER BLVD PORTLAND OR 97219 msr@nedc.org
NORTHWEST FOOD PROCESSORS ASSOCIATION	
DAVID ZEPPONI PRESIDENT	8338 NE ALTERWOOD RD, STE 160 PORTLAND OR 97220 pbarrow@nwfpa.org
NORTHWEST PIPELINE GP	
JANE HARRISON **(C)** MGR-MARKETING SERVICES	295 CHIPETA WAY SALT LAKE CITY UT 84108 jane.f.harrison@williams.com
BRUCE REEMSNYDER **(C)** SENIOR COUNSEL	295 CHIPETA WAY SALT LAKE CITY UT 84108 bruce.reemsnyder@williams.com
NW INDEPENDENT POWER PRODUCERS	
ROBERT D KAHN EXECUTIVE DIRECTOR	1117 MINOR AVENUE, SUITE 300 SEATTLE WA 98101 rkahn@nippc.org;rkahn@rdkco.com

OREGON AFL-CIO JOHN BISHOP	 1635 NW JOHNSON ST PORTLAND OR 97209 jbishop@mbjlaw.com
OREGON CATTLEMEN'S ASSOCIATION KAY TEISL	 3415 COMMERCIAL ST SE, SUITE 217 SALEM OR 97302 kayteisl@orcattle.com
OREGON DEPARTMENT OF ENERGY SUE OLIVER	 395 EAST HIGHLAND AVE HERMISTON OR 97838 sue.oliver@state.or.us
OREGON ENVIORNMENTAL COUNCIL JANA GASTELLUM PROGRAM DIRECTOR, GLOBAL WARMING	 222 NW DAVIS ST, STE 309 PORTLAND OR 97309-3900
OREGON FARM BUREAU FEDERATION KATIE FAST	 3415 COMMERCIAL ST SE SALEM OR 97302 katie@oregonfb.org
OREGON FOREST INDUSTRIES COUNCIL RAY WILKESON	 PO BOX 12826 SALEM OR 97309 ray@ofic.com
OREGON SIERRA CLUB IVAN MALUSKI	 1821 SE ANKEY ST PORTLAND OR 97214 ivan.maluski@sierraclub.org
OREGONIANS FOR FOOD AND SHELTER TERRY WITT EXECUTIVE DIRECTOR	 1149 COURT ST SE, STE 110 SALEM OR 97301 terry@ofsonline.org
PACIFIC ENVIRONMENTAL ADVOCACY CENTER AUBREY BALDWIN **(C)** STAFF ATTORNEY/CLINICAL PROFESSOR	 10015 SW TERWILLIGER BLVD PORTLAND OR 97219 abaldwin@lclark.edu
PACIFIC ENVIRONMENTAL ADVOCACY CENTER ALLISON LAPLANTE **(C)**	 10015 SW TERWILLIGER BLVD PORTLAND OR 97219 laplante@lclark.edu

PACIFIC POWER & LIGHT	
JORDAN A WHITE SENIOR COUNSEL	1407 W. NORTH TEMPLE, STE 320 SALT LAKE CITY UT 84116 jordan.white@pacificorp.com
PACIFICORP ENERGY	
PETE WARNKEN MANAGER, IRP	825 NE MULTNOMAH - STE 600 PORTLAND OR 97232 pete.warnken@pacificorp.com
PARETO ENERGY LTD	
GUY WARNER	1101 30TH ST WASHINGTON DC 20007 gwarner@paretoenergy.com
PHYSICIANS FOR SOCIAL RESPONSIBILITY-OREGON CHAPTE	
CATHERINE THOMASSON CLIMATE CHANGE CHAIR OREGON PSR	1227 NE 27TH #5 PORTLAND OR 97232 thomassonc@comcast.net
PORTLAND BUSINESS ALLIANCE	
BERNIE BOTTOMLY	200 SW MARKET, STE 150 PORTLAND OR 97201 bbottomly@portlandalliance.com
PORTLAND GENERAL ELECTRIC	
PATRICK G HAGER **(C)** MANAGER - REGULATORY AFFAIRS	121 SW SALMON ST 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
V. DENISE SAUNDERS **(C)** ASST GENERAL COUNSEL	121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 denise.saunders@pgn.com
POWER RESOURCES COOPERATIVE	
STEVE KING GENERATION RESOURCES MANAGER	711 NE HALSEY PORTLAND OR 97232-1268 sking@pngcpower.com
PUBLIC UTILITY COMMISSION	
MAURY GALBRAITH **(C)**	PO BOX 2148 SALEM OR 97308 maury.galbraith@state.or.us
RENEWABLE NORTHWEST PROJECT	
MEGAN WALSETH DECKER SENIOR STAFF COUNSEL	917 SW OAK, STE 303 PORTLAND OR 97205 megan@rnp.org
KEN DRAGOON	917 SW OAK, SUITE 303 PORTLAND OR 97205 ken@rnp.org

RICHARDSON & O'LEARY GREGORY M. ADAMS **(C)** ATTORNEY	 PO BOX 7218 BOISE ID 83702 greg@richardsonandoleary.com
RICHARDSON & O'LEARY PLLC PETER J RICHARDSON **(C)**	 PO BOX 7218 BOISE ID 83707 peter@richardsonandoleary.com
SALEM CHAMBER OF COMMERCE MIKE MCLARAN CHIEF EXECUTIVE OFFICER	 1110 COMMERCIAL ST SE SALEM OR 97301 mike@salemchamber.org; jason@salemchamber.org
SEDCOR RAYMOND BURSTEDT PRESIDENT	 625 HIGH ST NE, STE 200 SALEM OR 97301 rburstedt@sedcor.com
SIERRA CLUB LAW PROGRAM GLORIA D SMITH **(C)**	 85 SECOND STREET SAN FRANCISCO CA 94105 gloria.smith@sierraclub.org
TURLOCK IRRIGATION DISTRICT RANDY BAYSINGER ASSISTANT GENERAL MANAGER	 PO BOX 949 TURLOCK CA 95381-0949 rcbaysinger@tid.org
WESTSIDE ECONOMIC ALLIANCE JONATHAN F SCHLUETER	 10220 SW NIMBUS AVE, STE K-12 TIGARD OR 97223 jschlueter@westside-alliance.org
WILSONVILLE CHAPTER OF COMMERCE RAY PHELPS	 PO BOX 3737 WILSONVILLE OR 97070 rphelps@republicservices.com; steve@wilsonvillechamber.com