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September 26, 2011

NEW CASE

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. IPC-E-11-18
IN THE MATTER OF IDAHO POWER COMPANY'S REQUEST FOR ACCEPTANCE OF ITS REGULATORY PLAN REGARDING THE EARLY SHUTDOWN OF THE BOARDMAN POWER PLANT

Dear Ms. Jewell:

Enclosed for filing please find an original and seven (7) copies of Idaho Power Company's Application in the above matter.

Very truly yours,

Jason B. Williams

JBW:kkt
Enclosures

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NEW CASE

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S REQUEST FOR ACCEPTANCE OF ITS REGULATORY PLAN REGARDING THE EARLY SHUTDOWN OF THE BOARDMAN POWER PLANT.	CASE NO. IPC-E-11-18 APPLICATION

Idaho Power Company ("Idaho Power" or "Company"), in accordance with Idaho Code § 61-524 and RP 52, hereby respectfully makes Application to the Idaho Public Utilities Commission ("IPUC" or "Commission") for an Order that (1) accepts the Company's regulatory accounting and cost recovery plan regarding the early shutdown of the Boardman Power Plant ("Boardman") and (2) approves the establishment of a balancing account whereby incremental costs and benefits associated with the shutdown of Boardman will be tracked for recovery in a future proceeding. The Company does not seek current approval for rate recovery of future expenses associated with the Boardman shutdown at this time.

In support of this Application, Idaho Power represents as follows:

I. BACKGROUND

1. Boardman is a pulverized-coal plant located in north-central Oregon. It went into service in 1980 and consists of a single generating unit. Based upon currently approved depreciation rates, Boardman's expected plant life extends through at least 2030. Idaho Power owns a 10 percent interest, or 58.5 megawatts (net dependable capacity), in Boardman. After adjusting for routine scheduled maintenance periods and estimated forced outages, Idaho Power's share of the plant's annual energy generating capability is approximately 50 average megawatts. Portland General Electric ("PGE") has 65 percent ownership, Bank of America Leasing has 15 percent ownership, and Power Resources Cooperative has 10 percent ownership. As the majority partner of the plant, PGE operates the Boardman facility.

2. The Federal Clean Air Act requires that Oregon adopt and implement a plan to reduce visibility impacts to background levels by 2064 in designated areas (referred to as Class I areas). Oregon's plan to achieve this goal is referred to as the Oregon Regional Haze Plan ("Regional Haze Plan"). A draft of the Regional Haze Plan that included rules requiring specific emission reductions at Boardman by certain dates was issued by the Oregon Department of Environmental Quality ("DEQ") in December 2008 and was subsequently adopted with modifications by the Environmental Quality Commission ("EQC") on June 19, 2009. According to PGE, the EQC's modifications require "the installation of environmental controls as Best Available Retrofit Technology (BART) at the Boardman plant for the purpose of reducing visibility-impairing emissions and additional environmental controls as Reasonable Progress (RP) towards additional

haze causing emissions reductions." PGE 2009 Integrated Resource Plan ("IRP") Addendum, p. 88. The then-approved Regional Haze Plan required two phases – Phase 1 BART controls and Phase 2 RP controls, described as follows:

> Phase 1 compliance requires installation of Low NOx Burners and Modified Over-Fired Air ("LNB/MOFA") and semi-dry flue gas desulfurization (scrubbers) with an associated fabric filter. Phase 2 requires the installation of selective catalytic reduction (SCR). Under the existing Regional Haze Plan, PGE has the following options:
>
> - Install all of the controls: LNB/MOFA by July 2011, scrubbers/fabric filter by July 2014 and SCR by July 2017 and operate Boardman through 2040 or beyond (modeled in the "Diversified Thermal with Green" portfolios).
> - Install LNB/MOFA and scrubbers/fabric filters and cease Boardman operations in 2017; do not make the SCR investment (modeled in the "Boardman through 2017" portfolio).
> - Install LNB/MOFA only and cease Boardman operations in 2014 (modeled in the "Boardman through 2014" portfolio).
> - Cease Boardman operations in July 2011 with no obligation to install additional controls (modeled in the "Boardman through 2011" portfolio).

PGE 2009 IRP Addendum, p. 89.

3. In its 2009 IRP, PGE states that Boardman must meet these emissions requirements by either installing controls or ceasing operations altogether. PGE notes that "failure to comply with the plan can result in significant penalties, equitable remedies, and possibly criminal sanctions." PGE 2009 IRP, p. 294.

4. In addition to the Regional Haze Plan, Boardman is also subject to the Oregon Utility Mercury Rule ("Mercury Rule"), which requires installation of mercury

control equipment. The mercury control equipment installation is required by July 1, 2012. PGE plans to meet this requirement for Boardman in the following manner:

> . . . PGE determined that the injection of activated carbon upstream of the existing ESP [electrostatic precipitator] is most likely to result in the capture of at least 90 percent of the mercury contained in the coal. While this control approach is not optimal on a long-term basis, as there is material risk of rendering the ash unsellable, the approach enables PGE to substantially decrease mercury emissions prior to the time when a fabric filter can be installed.

PGE 2009 IRP, p. 294.

5. This approach will significantly decrease Boardman's mercury emissions while at the same time eliminating the need for a more expensive fabric filter equipment installation. PGE received approval of this mercury reduction plan from the DEQ, thus allowing PGE to provide a cost-effective solution for its customers.

II. BOARDMAN ANALYSIS

6. As part of its 2009 IRP, PGE analyzed "each of the Boardman-related controls technologies and associated deadlines" required under the Regional Haze Plan. PGE 2009 IRP, p. 295. A copy of the Boardman Analysis (Chapter 12) included in PGE's 2009 IRP is provided as Attachment No. 1.[1] Each of the Regional Haze Plan scenarios was analyzed as a separate portfolio with assumed end-of-life plant dates of 2040 (which included two portfolios: Diversified Thermal with Green and Diversified Green with On-Peak Energy Target), 2017, 2014, and 2011.

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[1] A complete copy of PGE's 2009 IRP can be found at: http://www.portlandgeneral.com/our_company/news_issues/current_issues/energy_strategy/docs/irp_nov2009.pdf.

7. PGE indicated the portfolio analyses provided a "comprehensive look at Boardman's value and risks" and took "into account expected cost, as well as price and reliability risk." PGE 2009 IRP, p. 307. A summary of PGE's results indicated:

> Overall, 'Diversified Thermal with Green' scored better than the Boardman 2014 portfolio . . . . The 'Diversified Thermal with Green' portfolio which includes Boardman through 2040 also clearly outperformed the early closure cases with respect to price risk and reliability. In general, although more exposed to CO_2 costs, the 'Diversified Thermal with Green' portfolio provides an effective hedge against natural gas price volatility, while maintaining system reliability at a relatively low cost.

PGE 2009 IRP, p. 307.

8. However, in January 2010, subsequent to the "Boardman through 2040" recommendation, rules recommended by the DEQ and requests from stakeholders suggested further analysis of a 2020 closure of Boardman.

9. PGE submitted an alternate proposal to the DEQ on April 2, 2010, requesting a petition that would allow for amendment to the Regional Haze Plan ("BART II Petition"). With the BART II Petition, PGE sought approval to shutdown or cease coal-fired operations at Boardman in 2020 while utilizing "a more limited emissions control upgrade package." PGE 2009 IRP Addendum, p. 89. With the BART II Petition, PGE:

> . . . would cut haze-causing emissions of sulfur dioxide and nitrogen oxides from the Boardman plant by:
>
> - Installing new, state-of-the-art LNB/MOFA burners by July 1, 2011. The new burners are expected to reduce nitrogen oxides emitted by the plant by nearly 50 percent.

- Using coal with a lower sulfur content to fire the plant's boiler. This would be completed in two stages as PGE's current coal supply contracts expire. In addition, PGE has recommended an initial 20 percent drop in permitted sulfur dioxide emissions that would take effect in 2011. This is followed by a further reduction in 2014 that would bring allowed sulfur dioxide emissions down by a total of 50 percent from current permit levels.

- Closing the plant in 2020, ending all coal-related emissions at least 20 years ahead of schedule and significantly reducing Oregon's contribution to green house gas emissions.

PGE 2009 IRP Addendum, pp. 89-90.

10. PGE analyzed the BART II Petition scenario ("Boardman through 2020") as part of its IRP portfolio analysis and filed an addendum to its 2009 IRP with the Public Utility Commission of Oregon ("OPUC") in April 2010 (see Attachment No. 2[2]). The analysis found that the "Boardman through 2020" portfolio performed better overall than all other alternatives. PGE stated that, the "'Boardman through 2020' portfolio strikes a good balance between the key risk drivers of natural gas and CO_2 prices, while maintaining system reliability at a relatively low cost." PGE 2009 IRP Addendum, p. 103. Based on this analysis, a 2020 closure of Boardman was included in PGE's preferred portfolio.

11. While the IRP portfolio analyses provide a comprehensive look at the costs and risks associated with various Boardman scenarios, PGE points out the following benefits the IRP analysis did not capture with regards to "Boardman through 2020":

[2] Attachment No. 2 is the Boardman Analysis (Chapter 12A) of PGE's 2009 IRP Addendum. A complete copy of the Addendum can be found at: http://www.portlandgeneral.com/our_company/news_issues/current_issues/energy_strategy/docs/irp_addendum.pdf.

- It preserves the near-term economic value of the plant thereby saving customers around $600 million dollars over the next decade compared to the earlier closure alternatives.

- It avoids the acceleration of additional costs and the corresponding customer rate pressure during a time when other IRP resource actions are also being implemented.

- It allows time for other greener technologies beyond wind to develop and economically mature, potentially allowing for a greater range of replacement options by 2020 than are available today for implementation by 2014.

- It provides a hedge against compliance costs of any future greenhouse gas legislation when compared to plans that operate Boardman through 2040.

- It allows for orderly transition for Boardman plant employees and the local community.

PGE 2009 IRP Addendum, p. 105.

12. The OPUC acknowledged PGE's 2009 IRP, including "Boardman through 2020" as the preferred portfolio, on November 23, 2010 (see Attachment No. 3). Shortly after, on December 9, 2010, the Oregon EQC approved revised BART rules "which require the installation of controls at Boardman to reduce NO_x and SO_2 in 2011 and a Dry Sorbent Injection system in 2014 to further address SO_2, with cessation of coal-fired operations by the end of 2020." PGE Advice 11-07 Attachment A – Discussion and Summary, p. 6. These revised rules were submitted as part of a revision to Oregon's Clean Air Act State Implementation Plan to the U.S. Environmental Protection Agency ("EPA") and were approved on July 5, 2011 (see Attachment No. 4).

13. In July 2011, a consent decree was filed with the U.S. District Court for the District of Oregon memorializing a settlement reached among the Sierra Club, four other

non-profit corporations and PGE related to Boardman. The Sierra Club and other plaintiffs had filed a complaint against PGE alleging Clean Air Act and opacity permit limit violations at Boardman. The consent decree provides that PGE will pay $2.5 million to the Oregon Community Foundation to be used for environmentally beneficial projects and will pay $1.0 million of the plaintiffs' legal expenses. Further, the consent decree imposes certain sulfur dioxide emission caps on the Boardman coal-fired boiler and would allow continued operation of Boardman until December 31, 2020. The consent decree is subject to approval of the court following a 45-day review period by the EPA and the U.S. Department of Justice. The consent decree was not contested during the 45-day review period and was approved by the Court on September 12, 2011.

III. PGE'S BOARDMAN ADJUSTMENT TARIFF

14. In late 2009, PGE filed a depreciation study with the OPUC requesting to update depreciation lives, curves, and net salvage rates for its plant accounts. Because PGE was in the process of developing its IRP portfolio analyses at the time the depreciation study was filed, and the Boardman end-of-life date had not been determined, the OPUC approved the new rates but indicated Boardman related items would be addressed at a later time. In February 2010, PGE filed a general rate case with the OPUC requesting a rate change effective January 1, 2011. Because the general rate case filing occurred before PGE had amended its 2009 IRP to include the 2020 Boardman closure date, PGE's test year expenses included depreciation rates and projected decommissioning costs for Boardman that assumed a December 31, 2040, end-of-life date. The filing also included a proposal for the Boardman Power

Plant Operating Life Adjustment Tariff ("Boardman Adjustment Tariff"), which is a mechanism that would allow for an update in rates to include the incremental revenue requirement resulting from a change in the Boardman end-of-life date. The mechanism is intended to capture annual changes to depreciation expense, amortization expense, and associated Schedule M and rate base adjustments until costs are incorporated into rates during a general rate case proceeding. The mechanism currently does not take into account capital costs associated with pollution control upgrades required at Boardman. The OPUC approved the Boardman Adjustment Tariff on December 17, 2010, with a zero dollar rate until a final determination was made on the Boardman closure date.

15. With "Boardman through 2020" recommended as the preferred portfolio and OPUC acknowledgement of this plan, PGE hired Black and Veatch ("B&V") to conduct a new decommissioning study based on the December 31, 2020, closure. In March 2011, B&V provided an initial estimate of total decommissioning costs less salvage of approximately $80 million in 2010 dollars. PGE Advice 11-07 Staff Report, p. 3. On April 4, 2011, PGE submitted an advice filing with the OPUC requesting a seven-month incremental revenue requirement increase of $9.3 million associated with the Boardman Adjustment Tariff. The rate request included the incremental depreciation expense and additional decommissioning costs associated with the Boardman December 31, 2020, closure. The advice filing was approved by the OPUC effective July 1, 2011.

IV. IDAHO POWER'S BOARDMAN PLAN

16. As a 10 percent owner in Boardman, Idaho Power is directly impacted by PGE's decision for a 2020 closure. In addition to providing the Commission with information regarding PGE's evaluation of Boardman's need to meet Oregon emission reduction rules, this filing is intended to detail Idaho Power's proposed plan for responding to the 2020 decommissioning of Boardman. The Company does not request recovery of any incremental costs associated with the Boardman closure at this time. However, Idaho Power requests that the Commission acknowledge its support for a proposed regulatory and accounting plan for responding to the plant closure. The Company respectfully requests acknowledgement of support of the plan by mid-February 2012 to allow time to prepare necessary regulatory filings.

17. In response to PGE's currently approved plan for a 2020 shutdown of Boardman, Idaho Power has developed a proposed regulatory and accounting strategy that involves three primary steps. First, the Company plans to begin a new depreciation study that it will file with the Commission in early 2012. This filing will request new depreciation rates for all plant investment, including Boardman, to become effective June 1, 2012. Second, the Company proposes the establishment of a balancing account to track the incremental costs and benefits that will exist as a result of the Boardman shutdown. Third, the Company plans to file a request with the Commission in early 2012 for authorization to increase customers' rates to recover future Boardman decommissioning costs to become effective June 1, 2012, coincident with the change in depreciation rates.

V. DEPRECIATION STUDY

18. Boardman's depreciation rates were established as part of Idaho Power's most recent depreciation study, which was performed in 2008 based on December 31, 2006, plant values. Both the Commission and the OPUC have instructed the Company to file depreciation studies approximately every five years, with the next study scheduled for 2013. However, in light of Boardman's early closure and the soon to be completed 330 megawatt Langley Gulch Power Plant, the Company has retained a consultant, Gannett Fleming, Inc., to perform a depreciation study. This study will evaluate *all* plant accounts, acknowledging the closure of Boardman in 2020 and associated decommissioning costs. Idaho Power anticipates filing a request for new depreciation rates for all plant accounts in early 2012, with a change in rates requested to occur June 1, 2012.

19. Currently, depreciation rates associated with Boardman plant accounts include a portion related to estimated net salvage values of Boardman facilities as of December 31, 2040. The net salvage component of the depreciation rate is intended to minimize potential stranded costs at the time of final retirement but does not include specific decommissioning costs. Rather, the estimated Boardman decommissioning costs are accounted for as an Asset Retirement Obligation ("ARO") under Financial Accounting Standards Board Accounting Standards Codification ("ASC") 410. In accordance with IPUC Order No. 29414, Idaho Power records, as a regulatory asset, the cumulative financial statement impact resulting from the Company's implementation of ASC 410 (previously Statement of Financial Accounting Standards 143), and the ongoing annual differences between the ASC 410 depreciation and accretion expenses

and the annual depreciation expenses that are currently authorized by the Commission in depreciation rates and reclamation accruals. With the change in the Boardman closure date and an updated decommissioning study, the Company now has a more accurate estimate of expected decommissioning costs. In their 2011 study, B&V assumed a December 31, 2020, decommissioning of Boardman and based costs on the assumption that the site would be returned to the same conditions that existed prior to its construction. As described by PGE:

> In addition to the main power block, the ancillary facilities to be decommissioned include offices, shops, warehouses, evaporative lagoons, settling ponds, the water supply well, the coal storage area, coal handling facilities, the ash disposal area, Carty reservoir, a 15-mile rail spur, several miles of the privately-owned portion of Tower Road, and two 17-mile transmission lines[3]. The estimate also includes all currently known disposal and environmental clean up costs. As part of the study, B&V calculated the scrap value of all useful metals and materials and used this value to offset overall decommissioning costs.

PGE Advice 11-07, p. 4

20. In its revenue requirement calculation, PGE included the straight-line recovery of the future value of the projected decommissioning costs with the exception of two items from B&V's decommissioning cost estimate because it felt there was too much uncertainty around the following items: costs for decommissioning the ash pile and remaining coal supply costs. PGE's rationale for adjusting current rates to recover future decommissioning costs is based on the premise that current customers receiving the benefits of Boardman's generation will be the same customers that pay for the costs to decommission the plant. This matching approach, which was ultimately approved by

[3] PGE has subsequently decided that no transmission lines associated with the Boardman plant will be decommissioned.

the OPUC, is also the methodology preferred by Idaho Power. The Company will continue to estimate its share of decommissioning costs using the decommissioning costs by multiplying PGE's total estimate and applying the Company's 10 percent ownership percentage.

VI. BOARDMAN BALANCING ACCOUNT

21. Based upon PGE's plan to cease operations of Boardman in 2020, Idaho Power expects to incur incremental costs associated with the accelerated depreciation of the plant, new investment related to pollution controls, and costs associated with the decommissioning of the plant.[4] While the incremental depreciation expense for current investment is easily calculated based upon the current shutdown timeline, the specific level of investment in capital additions, actual decommissioning costs, and potential salvage proceeds are not yet known. With the approval of PGE's Boardman shutdown plan by the OPUC and the EPA, the incremental cost impacts are certain to occur. However, the exact impact is not yet known. For that reason, Idaho Power proposes the establishment of a balancing account that would allow flexibility for the timing and recovery of the incremental revenue requirement. A balancing account would allow for the tracking, on a cumulative basis, of the difference between revenues and expenses associated with the Boardman shutdown and ensure that customers pay no more and no less than the actual expenditures.

22. In addition to providing a mechanism to track the revenue requirement impacts associated with Boardman, a balancing account would likely mitigate the possibility that the shutdown of Boardman in 2020 would result in impairment under

[4] There may be opportunities to continue serving customers with a different fuel at the Boardman site. For example, PGE is investigating the possibility of using giant cane as a biofuel.

FASB Accounting Standards Codification ("ASC") 360, *Property, Plant and Equipment*. ASC 360 states that an impairment loss shall be recognized if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. Under ASC 360, Idaho Power would potentially be required to record an impairment loss if not allowed to recover the full amount of the Boardman-related balances, and thus having an adverse financial impact on the Company.

23. In addition, ASC 980-360-35 states that when it becomes probable that an operating asset will be abandoned, the cost of the asset must be removed from plant-in-service and set up as a regulatory asset and any disallowed amount be recognized as a loss. Idaho Power concluded that the decision to shutdown Boardman by December 31, 2020, is not an abandonment of Boardman; rather, it is an adjustment to Boardman's useful life. Adjustments to the useful life of Boardman have previously occurred in 2001 from an original end-of-life date of 2015 to 2020 and most recently in 2008 to an end-of-life date of 2030. If, however, Idaho Power is not allowed to collect the Boardman plant-related balances by the end-of-life date of December 31, 2020, Idaho Power could be required to account for the Boardman plant as an abandonment, which would also trigger impairment treatment under ASC 360.

24. Idaho Power has prepared a preliminary estimate of a revenue requirement using a 2012 test year that includes impacts resulting from the accelerated depreciation of the Boardman plant accounts and from increased decommissioning costs. Incremental depreciation expense was based on expected December 31, 2011,

plant balances and the decommissioning costs were calculated using Idaho Power's 10 percent share of the costs PGE found reasonable in the B&V study. The preliminary estimate results in a revenue deficiency of approximately $1.45 million on a *total system basis*, or $1.38 million for the Idaho jurisdiction (see Attachment No. 5).

VII. SUMMARY OF ATTACHMENTS

25. Attachment No. 1 to this Application is a copy of the Boardman Analysis (Chapter 12) included in PGE's 2009 IRP.

26. Attachment No. 2 to this Application is the Boardman Analysis (Chapter 12A) of PGE's 2009 IRP Addendum.

27. Attachment No. 3 to this Application is a copy of Order No. 10-457, the OPUC's acknowledgment of PGE's 2009 IRP, including the Addendum.

28. Attachment No. 4 to this Application is a copy of the EPA's approval of the revision to Oregon's Clean Air Act State Implementation Plan.

29. Attachment No. 5 to this Application is the preliminary estimate of the Idaho jurisdictional revenue deficiency resulting from the accelerated depreciation of the Boardman plant accounts and the increased decommissioning costs.

VIII. MODIFIED PROCEDURE

30. Idaho Power believes that a hearing is not necessary to consider the issues presented herein and respectfully requests that this Application be processed under Modified Procedure; i.e., by written submissions rather than by hearing. RP 201 *et seq*. If, however, the Commission determines that a technical hearing is required, the Company stands ready to present its testimony and support the Application in such hearing.

IX. COMMUNICATIONS AND SERVICE OF PLEADINGS

31. Communications and service of pleadings with reference to this Application should be sent to the following:

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X. CONCLUSION

32. PGE's currently approved plan for the 2020 shutdown of Boardman represents a reasonable combination of least-cost and least-risk compliance with the Federal Clean Air Act requirements. This plan will bring with it certain increased revenue requirements for Idaho Power-related to accelerated depreciation expense, additional plant investments, and decommissioning costs. Therefore, Idaho Power requests that the Commission acknowledge its support for the Company's proposed regulatory plan and grant the Company's request to establish a balancing account to track incremental costs and benefits associated with Boardman decommissioning and shutdown activities.

XI. REQUEST FOR ACCEPTANCE

33. Idaho Power respectfully requests that the Commission issue an Order by mid-February 2012 (1) authorizing that this matter may be processed by Modified Procedure, (2) accepting the Company's Boardman plan as set forth above, and (3)

approving the establishment of a balancing account to track costs and benefits associated with the early shutdown of Boardman.

DATED at Boise, Idaho, this 26th day of September 2011.

Lisa Nordstrom for

JASON B. WILLIAMS
Attorney for Idaho Power Company

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-18

IDAHO POWER COMPANY

ATTACHMENT NO. 1

12. Boardman Analysis

Boardman is a key resource for PGE. It is a low-cost, baseload plant that enables us to provide 15% of our customers' energy needs with a reliable, stable source of power. The plant also contributes to the diversity of our supply mix. Due to efficiency upgrades, Boardman is in the top quintile among U.S. coal plants for efficiency (heat rate) in converting fuel to electricity. Those same upgrades mean that many of the major components of the plant are comparatively new making it likely that Boardman will continue to operate reliably and efficiently for many years into the future.

In this chapter we describe the emissions controls required under the recently approved Oregon Regional Haze Plan and the Oregon Utility Mercury Rules. We also describe how our scenario and stochastic analyses indicate that the best combination of expected costs and associated risks and uncertainties for our customers is achieved in a portfolio in which PGE invests in the required emissions controls and continues to operate Boardman through 2040.

Chapter Highlights

- PGE's Boardman and Beaver generating plants are subject to an assessment of emissions sources pursuant to the Oregon Regional Haze Plan.
- PGE has also developed a cost estimate for the installation of emissions controls at Boardman, as required by the Oregon Regional Haze Plan and the Oregon Utility Mercury Rule.
- Portfolio analysis used in this IRP favors continued operation of Boardman. PGE recommends investment in emissions controls technology as detailed in the Oregon Regional Haze Plan and Oregon Utility Mercury Rule, with operation of Boardman through 2040.

12.1 Boardman Plant Overview

Boardman is a pulverized-coal plant located in north-central Oregon approximately 13 miles southwest of the city of Boardman, and 160 miles east of Portland. It went into service in 1980. Its expected plant life extends through at least 2040. Coal for Boardman is transported by rail from the Powder River Basin (PRB) coal mines of central Wyoming. PGE is the operator of the plant, and we have a 65 percent ownership interest, or 380-MW share of the plant output. Forecasted average annual energy availability for PGE's share is 318 MWa. The 585-MW net capacity output serves the equivalent of about 341,500 residences.

The Boardman area was chosen for the plant's location because it has good access to land, water, transmission and rail transportation. A large cooling pond, Carty reservoir, was built to provide cooling water for the plant. The pond eliminates the need for returning cooling water to natural streams or rivers, thus avoiding discharge that might impact fish and wildlife. It also minimizes the draw on river water.

The fuel is a low-sulfur sub-bituminous coal, primarily from the PRB mines. Coal is transported to the plant by railcar. Boardman can stockpile up to 400,000 tons of PRB coal at the on-site coal yard, the equivalent of 55 days at full operations.

Boardman typically shuts down once a year in the spring to perform its annual planned maintenance. The plant is primarily a base-load resource, but is economically dispatched during some periods where regional loads and prices are low. Economic dispatch and load cycling generally occurs only in the spring.

12.2 Oregon Regional Haze Plan

Section 169A of the Federal Clean Air Act (as implemented through 40 CFR 51.308) requires that Oregon adopt and implement a plan to reduce visibility impacts in designated areas (referred to as Class I areas) to background levels by 2064. Oregon's plan to achieve this visibility goal is referred to as the Oregon Regional Haze Plan or the Plan. The Oregon Department of Environmental Quality (DEQ) issued a draft Oregon Regional Haze Plan for public comment in December 2008. The Plan included rules that would require specific emission reductions at the Boardman plant by dates identified in the proposed rules. During the public comment period PGE proposed an alternative approach whereby PGE would have to decide, at dates certain, to either proceed with the next phase of controls or cease operations at the Boardman plant by a specific date after the date that controls were otherwise required. This plan would have provided PGE the flexibility to address the general uncertainty associated with future electric prices and potential changes in legislation impacting generation.

Specifically, it would have allowed PGE to consider through future IRP processes the cost-effectiveness of implementing the controls in light of changes to natural gas and coal prices, as well as CO_2 allowance prices.

The added flexibility would have enabled PGE to have access to better information about gas, coal and carbon prices at the time the investment decision would be made, thus reducing the financial risk to customers. PGE's proposal recognized that time is the only effective hedge against the uncertainty surrounding upcoming carbon legislation as well as the commodities markets.

On June 19, 2009 the Environmental Quality Commission (EQC) adopted DEQ's proposed Oregon Regional Haze Plan, as modified in response to public comment. The Oregon Regional Haze Plan, as adopted, did not include PGE's proposal and largely consisted of the approach DEQ proposed for public comment. The Oregon Regional Haze Plan requires the installation of environmental controls at the Boardman plant for the purpose of reducing visibility-impairing emissions.

The Plan calls for a two-phase approach identified as Phase 1 – Best Available Retrofit Technology and Phase 2 – Reasonable Progress. Phase 1 (OAR 340-223-0030) requires compliance with a reduced nitrogen oxides (NOx) limit by 2011 and a reduced sulfur dioxide (SO_2) and particulate matter (PM) limit by 2014. The NOx limit was based on the assumption that PGE would install combustion controls (low-NOx burners and modified over-fired air or LNB/MOFA). If compliance with this limit is not demonstrated by July 1, 2012, then DEQ can grant an extension until July 1, 2014 under the condition that the emissions meet a more restrictive NOx limit. The SO_2 and PM limits are based on the installation of semi-dry flue gas desulfurization (scrubbers) with an associated fabric filter. Phase 2 (OAR 340-223-0040) requires compliance with a further-reduced NOx limit by 2017. This limit was based on the assumption that PGE would install selective catalytic reduction (SCR).

Under these rules, PGE has the following options:

- Install all of the controls: LNB/MOFA by July 2011, scrubbers/fabric filter by July 2014 and SCR by July 2017 and operate Boardman through 2040 or beyond.
- Install LNB/MOFA and scrubbers and cease Boardman operations in 2017; do not make the SCR investment.
- Install LNB/MOFA only and cease Boardman operations in 2014.
- Cease Boardman operations in July 2011 with no obligation to install additional controls.

Non-compliance with the Oregon Regional Haze Plan (and also Oregon Utility Mercury Rule) is, however, not an option. The plant must meet emissions requirements by either installation of controls or by ceasing operations. Failure to comply with the plan can result in significant penalties, equitable remedies, and possibly criminal sanctions.

12.3 Oregon Utility Mercury Rule

In addition to the Oregon Regional Haze Plan, Boardman is also subject to the Oregon Utility Mercury Rule. PGE conducted a detailed engineering cost analysis as well as a study on the impact these modifications will have on operating and maintenance costs once installed. When the Oregon Utility Mercury Rule was first adopted, DEQ, PGE and the public anticipated that the mercury limits would take effect at the same time as the Oregon Regional Haze Plan requirements. This expectation arose from the Department's intent to establish a multi-pollutant strategy whereby mercury, SO_2, and particulate matter (PM) would all be addressed by an integrated control system. However, delays in the development of the Oregon Regional Haze Plan have resulted in the SO_2 scrubber and PM control compliance date being extended to July 1, 2014—two years after the date that the mercury emission standards take effect. The mercury rule revisions adopted by the Environmental Quality Commission (EQC) on June 19, 2009, authorize a two-year compliance extension in the event that it is not practical for PGE to install mercury controls by July 1, 2012, due to supply limitations, electrostatic precipitator (ESP) fly ash contamination or other circumstances beyond PGE's control.

However, based on pilot testing results, PGE determined that the injection of activated carbon upstream of the existing ESP is most likely to result in the capture of at least 90 percent of the mercury contained in the coal. While this control approach is not optimal on a long-term basis, as there is material risk of rendering the ash unsellable, the approach enables PGE to substantially decrease mercury emissions prior to the time when a fabric filter can be installed. Therefore, PGE is submitting for DEQ approval a mercury reduction plan in accordance with OAR 340-228-0606(1). PGE believes that this plan complies with all rule requirements and will enable a high level of mercury control in reliance on the existing ESP until such time that the scrubbers and associated fabric filter is installed consistent with the Oregon Regional Haze Plan. At that time, the activated carbon injection point will be moved to enable collection of the carbon (and mercury) in the fabric filter. The costs of this approach were included in our modeling.

12.4 Boardman Portfolio Analysis

As part of the IRP overall economic analysis, each of the Boardman-related controls technologies and associated deadlines were modeled in AURORAxmp as distinct portfolios. Boardman-specific assumptions in these portfolios are listed below by the following assumed plant run-through dates:

- 2040: Install all of the controls: LNB/MOFA by July 2011, scrubbers by July 2014 and SCR by July 2017 and operate Boardman through 2040 (the "Diversified Thermal with Green" and "Diversified Green with on-peak Energy Target" portfolios).

- 2017: Install LNB/MOFA and scrubbers; cease Boardman operations in mid-2017; no SCR investment. Assumes the addition of a CCCT for energy replacement in 2017 ("Boardman through 2017").

- 2014: Install LNB/MOFA; cease Boardman operations in mid-2014; no further emissions controls investment. Assumes a CCCT for energy replacement online in 2015 (earliest online date for a greenfield CCCT), with market power purchases to bridge through remainder of 2014. ("Boardman through 2014").

- 2011: Cease Boardman operations in July 2011 with no obligation to install additional controls. Assumes a fixed price power purchase through 2014 as a bridge strategy, and then the addition of a CCCT in 2015. ("Boardman through 2011").

Except for the above-noted differences, all of these portfolios are built on the "Diversified Thermal with Green" portfolio assumptions as the starting point. PGE used both scenario (deterministic) as well as stochastic analyses in evaluating the Boardman portfolios. For the scenario analysis, PGE uses AURORAxmp to calculate a Net Present Value of Revenue Requirements (NPVRR) for each portfolio under 21 differing potential futures, starting with a reference case. For the stochastic analysis, PGE "shocks" the following five input variables: WECC-wide load, natural gas prices, historic water years (for PGE only), plant forced outages, and the intermittency of wind production. Detailed descriptions of our portfolios and analytical approach are in Chapter 10.

12.5 Results of Portfolio Analysis

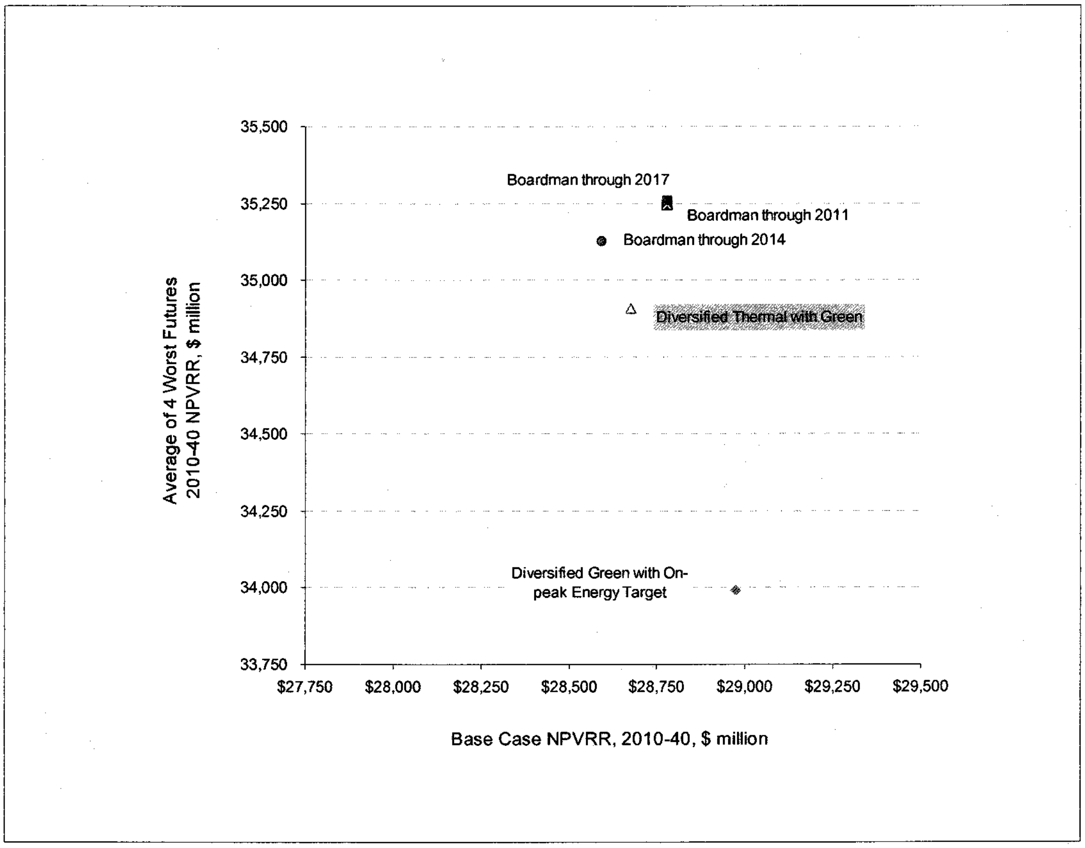
Please refer to Chapter 10 for a detailed description of our portfolio analysis approach.

Deterministic Portfolio Analysis Results

The Trade-off between Expected Cost and Associated Risk

The relationship between expected costs and the associated risk of each portfolio provides a good way to quickly assess the relative performance of portfolios. In this IRP, for each portfolio PGE uses the expected NPVRR from the reference case future as the measure for expected cost (plotted on the X-axis in Figure 12-1) and the average NPVRR of the four worst futures as the measure for portfolio cost risk (plotted on the Y-axis in Figure 12-1). Portfolios that for a given level of risk have the lowest cost, or for a given cost have the lowest risk, are deemed to be efficient.[92] Visually, portfolios that plot closer to the origin generally outperform portfolios located further from the origin.

Figure 12-1: Efficient Frontier for Boardman Portfolios



[92] While this is not the same as an efficient frontier as defined in financial portfolio theory, the concept of looking at the trade-off between a return (or cost in this case) and its associated risk is similar. Thus, at times we refer to a portfolio as being on an efficient frontier, meaning that the portfolio performs better than others when considering both expected cost and risk.

Three of the five Boardman portfolios are efficient. Portfolios titled "Diversified Thermal with Green" and "Boardman through 2014" outperform the third efficient portfolio "Diversified Green with On-peak Energy Target" based on expected cost. As a result, we focus on them. The remaining portfolios "Boardman through 2011" and "Boardman through 2017" proved to be both more costly and risky, and therefore are not efficient. When compared to "Diversified Thermal with Green," these two portfolios are both more costly and more risky (by more than $100 million and $300 million respectively). When compared to "Boardman through 2014", expected costs for these two portfolios are almost $200 million greater. These portfolios also have a higher risk by more than $100 million.

The "Diversified Thermal with Green" and "Boardman through 2014" both outperform the other Boardman choices. Between these two choices, "Boardman through 2014" has a lower expected cost by $81 million, while performing worse on the risk measurement by approximately $200 million. For every dollar of expected cost incurred by choosing "Diversified Thermal with Green" over "Boardman through 2014", risk exposure can be reduced by roughly $2.20. In other words the risk differential is more than two times the cost differential.

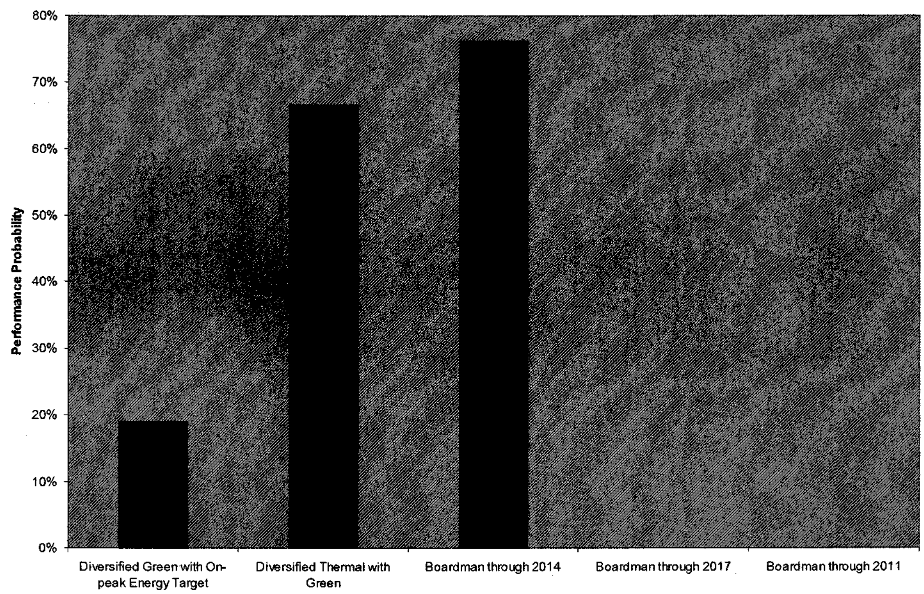
On the graphs in this section, for comparison, we also show our two top-performing portfolios with Boardman operating through 2040, "Diversified Green with On-Peak Energy Target" and "Diversified Thermal with Green".

Portfolio Durability: Combined Probability of Achieving Good and Avoiding Bad Outcomes

Although the deterministic approach to portfolio analysis does not assign probabilities to the likelihood of a particular future taking place, one way to look at portfolio durability is to count the frequency of good outcomes vs. bad outcomes. A bad outcome is defined as the number of times that a given portfolio ranks among the worst four out of the 15 portfolios we tested against all 21 futures. And conversely, a good outcome is defined as the number of times that a given portfolio ranked among the best four out of the 15 portfolios we tested against all 21 futures. The goal is to avoid bad outcomes while seeking good outcomes.

Better portfolios have a high probability of *combined* good vs. bad outcomes. In our scoring, a portfolio that always ranked in the top four would get a 100% score, a portfolio that always ranked in the bottom four would get a -100%. Mediocre portfolios that had mixed results would score 0%. The same two portfolios that lie on the efficient frontier ("Diversified Thermal with Green" and "Boardman through 2014") also outperform all other Boardman options in this metric – see Figure 12-2. "Boardman through 2014" and "Diversified Thermal with Green" resulted in scores of 67% and 76% respectively, meaning that these portfolios are comparatively durable when evaluated against most futures. On the other hand, "Boardman through 2011" and "Boardman through 2017" both resulted in a score of 0%.

Figure 12-2: Combined Probability of Good and Bad Outcomes for Boardman Portfolios



Scenario Risk Magnitude

This metric addresses the magnitude of adverse outcomes. It is the cost difference between the reference case performance of a given portfolio vs. the average performance within the four worst futures for each portfolio. The best portfolio would have the lowest score for this metric. "Diversified Green with On-Peak Energy Target" performs best when compared to other Boardman alternatives with a portfolio risk magnitude of $5 billion. Second best is "Diversified Thermal with Green" with a risk magnitute of $6.2 billion, "Boardman through 2014", "Boardman through 2011" and "Boardman through 2017"have a similar risk magnitude of approximately $6.5 billion.

Summary of Results from Deterministic Measures:

Our portfolio scoring includes three measurement categories from the deterministic portfolio analysis: Expected Cost, Risk Durability and Risk Magnitude (Risk Magnitude includes Average of the four worst cases, as well as Average of the four worst cases vs. Reference Case). In all, four deterministic measurements comprised 70% of the combined score (see Table 12-2). Both "Diversified Thermal with Green" and "Boardman through 2014" perform materially better than "Boardman through 2011" and "Boardman through 2017" with respect to the deterministic portion of the score. "Boardman through 2014" slightly outperforms "Diversified Thermal with Green" by 1% of the deterministic portion of the score.

Stochastic Portfolio Analysis Results

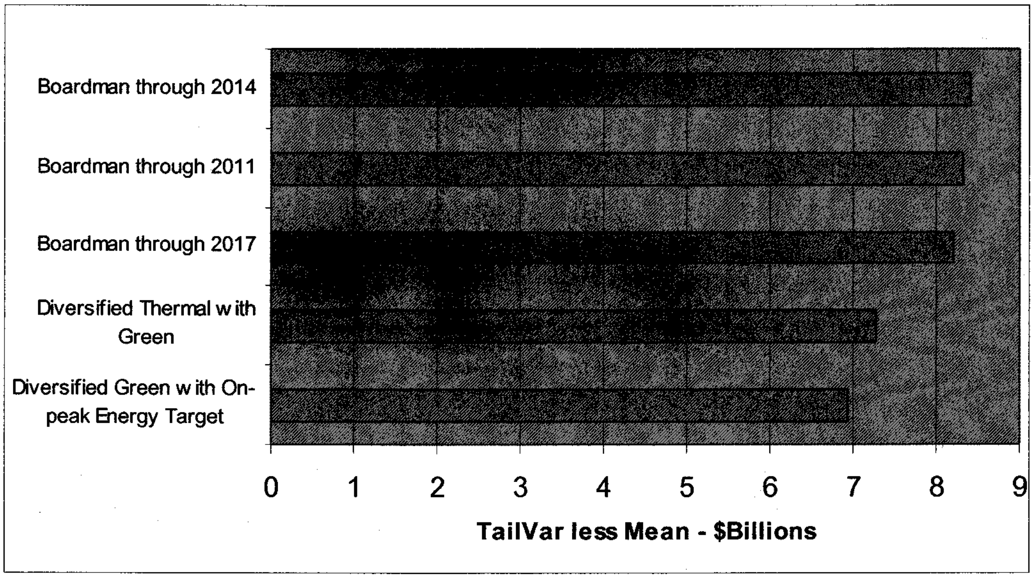
By stochastically modeling WECC-wide load, natural gas prices, historic water years, plant forced outages and the intermittency of wind production, we were able to assess probabilistic metrics of Boardman portfolio risks. As detailed in Chapter 10, the portfolios were run 100 times subject to stochastic variations in the above variables. For stochastic analysis, we employ a NPVRR TailVar less Mean to look at portfolio risk over our dispatch modeling horizon of 2010 to 2040, as well as a year-to-year variability metric.

TailVar 90 less Mean:

This metric measures the right-tail risk or *magnitude* of bad outcomes for each individual portfolio, as measured by averaging the portfolio NPV that resides in the most expensive 10% of the distribution (right tail risk) and subtracting from this the portfolio mean NPV (i.e., expected cost). The result is a measure of how widely a portfolio can deviate from its expected cost.

The "Diversified Thermal with Green" portfolio has a TailVar 90 less Mean amount of $7.2 billion compared to $8.4 billion, $8.3 billion and $8.2 for "Boardman through 2014", "Boardman through 2011" and "Boardman through 2017" respectively – see Figure 12-3. "Diversified Thermal with Green" outperforms the other Boardman alternatives by more than $1 billion on average. These results show the increased risk exposure when moving from coal as a fuel to a greater concentration of natural gas, which has more volatile prices.

Figure 12-3: Stochastic Risk – TailVar less Mean for Boardman Portfolios

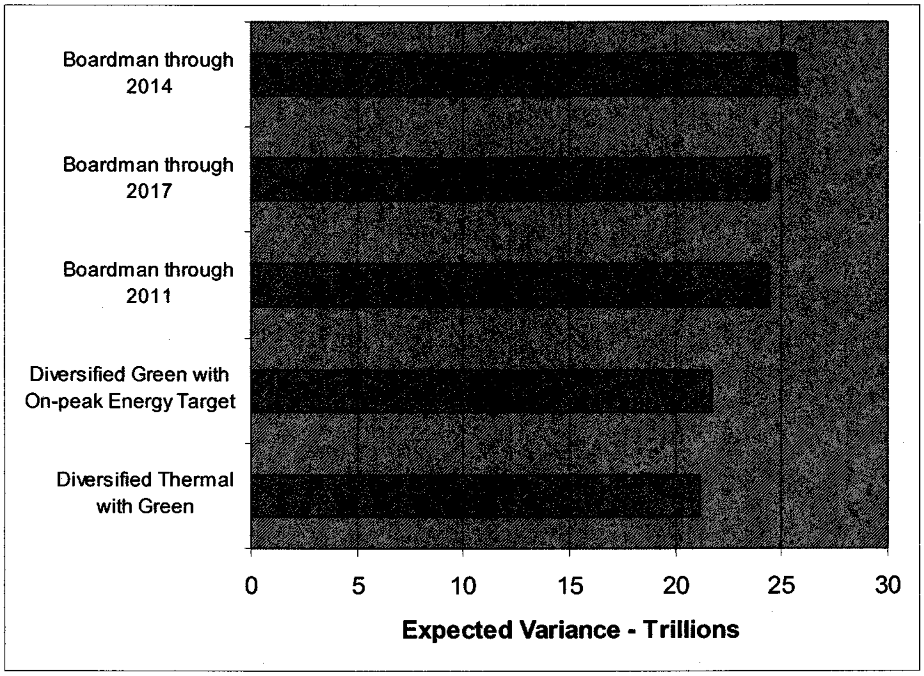


Stochastic Year-to-Year Variation

This metric addresses the innate volatility of a given portfolio. It measures the average year-over-year variation, based on 100 independent iterations of the stochastic inputs. While the "TailVar less mean" measures the worst 10% possible outcome of the expected portfolio costs over the 31 forecast years, the "Year-to-Year Variation" metric measures changes in year-to-year portfolio costs. In other words, "TailVar less Mean" measures "how bad can the worst outcomes be?" over the life of the portfolio while "Year-to-Year Variation" measures "how bumpy is the road?" for a particular portfolio.

The best portfolio would have the lowest year-to-year variation. As shown in Figure 12-4 below, "Diversified Thermal with Green" outperforms the other Boardman portfolios with an expected variation of 21 trillion compared to "Boardman through 2014", "Boardman through 2011" and "Boardman through 2017" all with expected variations exceeding 24 trillion.

Figure 12-4: Stochastic Risk – Year-to-Year Variation for Boardman Portfolios



Summary of Results from Stochastic Measures

We included in scoring three measurement categories from the stochastic portfolio analysis: TailVar, TailVar less Mean and Year to Year Variation. Stochastic measurements comprised 10% of the total weighed combined score (see Table 12-2). Diversified Thermal with Green performs materially better than the other three Boardman portfolios by an average of 31% of the stochastic portion of the score.

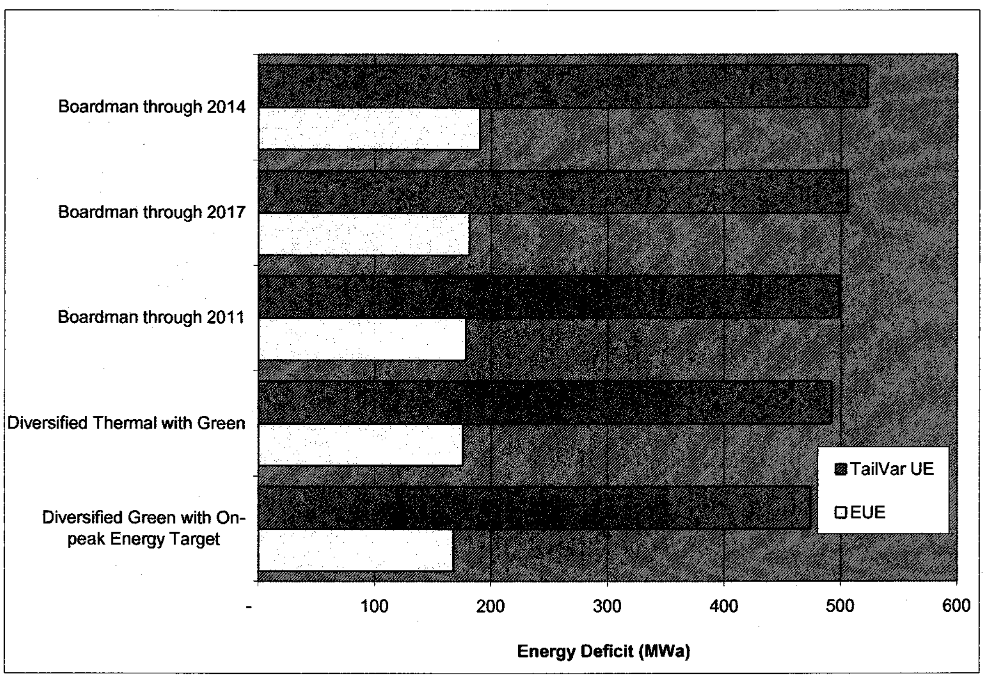
Reliability and Diversity Analysis Results

Tailvar Unserved Energy

We calculate the Tailvar Unserved Energy (Tailvar UE) as the average of the worst 10% of outcomes (across 100 iterations where PGE's plants are subject to random forced outages and associated mean times to repair) of the amount of power PGE must purchase on the spot market in order to meet customer load. Expressed in MWa, market purchases are required when PGE's owned and contracted resources are insufficient to meet customer load. This metric is calculated as the average for all years from 2010 through 2020, plus 2025. The higher the amount, the less reliable that portfolio is relative to the other portfolios.

"Diversified Green with On-peak Energy Target" is the most reliable based on the Tailvar and EUE metrics – see Figure 12-5. In our inputs, we assume that the Boardman plant has a higher forced outage rate compared to a CCCT replacement. The "Boardman through 2014" portfolio, fares somewhat worse than the "Boardman through 2011" portfolio because the 2014 closure assumes that PGE must rely on spot market purchases until a replacement resource can be brought on-line.

Figure 12-5: Unserved Energy Metrics for Boardman Portfolios, 2012-2020 & 2025



Technology and Fuel Diversity

PGE has applied the Herfindahl-Hirschman Index (HHI), which has traditionally been used to measure concentration of commercial market power. In this case, the HHI is used to measure the portfolio concentration in technologies and fuels (coal, natural gas, hydro, wind, market purchases, etc.) from 2010 through 2020.

A lower value means less portfolio concentration in any given technology or fuel type over the period. A lower HHI value is preferred as it indicates higher portfolio diversity and thus less exposure to fuel and generation technology driven risks. The diversified portfolios outperform all of the early Boardman closure portfolios from fuel and technological perspectives. See Figure 12-6 and Figure 12-7 below respectively. While the early Boardman closure portfolios are equivalent on a technological basis, the later closures perform better from a fuel diversity perspective.

Figure 12-6: Herfindahl-Hirschman Index Boardman Fuel Results

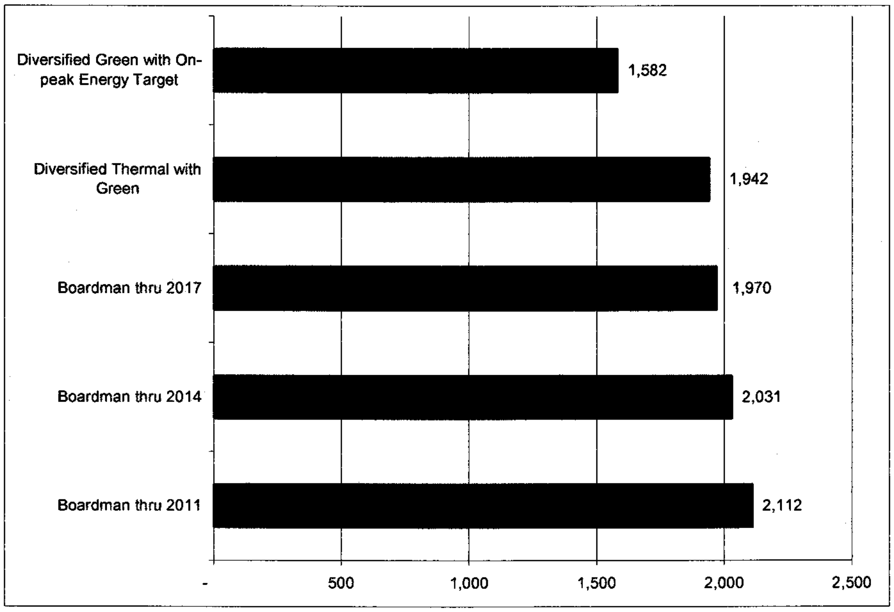
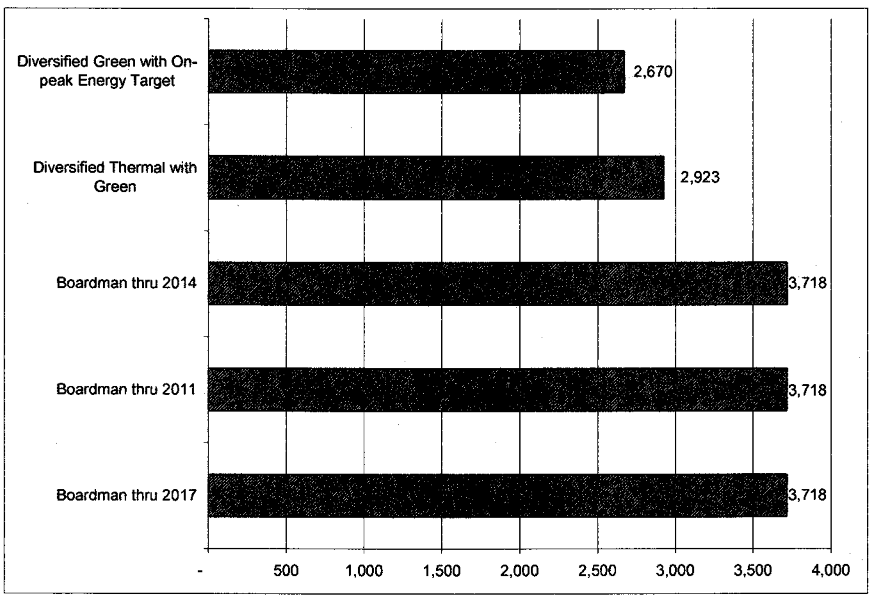


Figure 12-7: Herfindahl-Hirschman Index - Boardman Technological Results



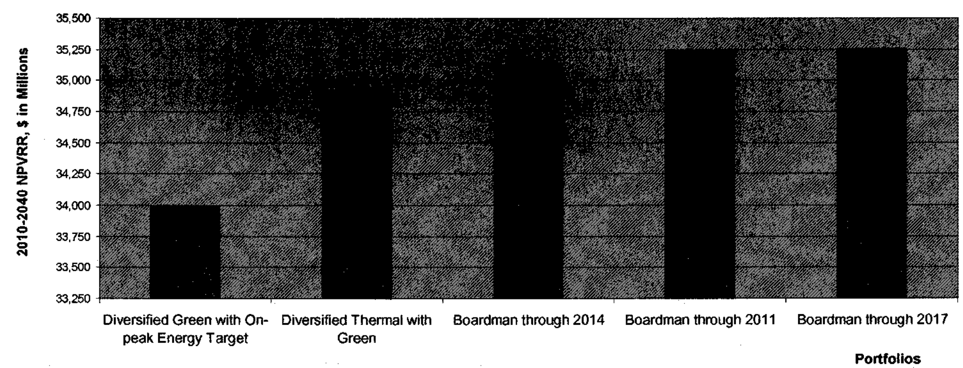
Summary of Results from Reliability and Diversity Measures

We included in scoring three measurement categories from the reliability and diversity portfolio analysis: Tailvar UE, Technology HHI and Fuel HHI. Reliability and Diversity measures comprised 20% of the total weighed combined score (see Table 12-1). Diversified Thermal with Green performs materially better than the other three Boardman portfolios.

Other Metrics

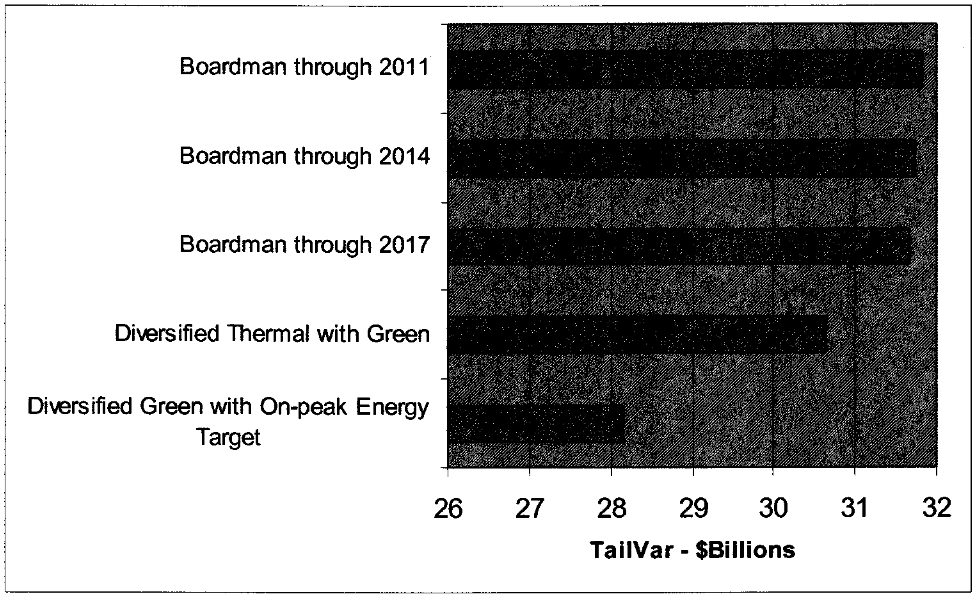
At the recent suggestion of OPUC Staff, PGE has added a variation of two metrics described above to its scoring. Rather than look solely at the deterministic average of the worst four futures less the reference case expected cost and the similar stochastic metric of TailVar 90 less the Mean, we have added these two right-tail metrics as absolute measurements without subtracting from a mean value. This allows for an absolute look at risk exposure without being influenced by distance from the mean. These metrics do not have a significant impact on the top-performing portfolios, particularly given the relatively small weights they have been assigned in the scoring matrix. Figure 12-8 shows the average NPVRR for the four worst future outcomes. "Diversified Green with On-peak Energy" has the lowest NPVRR of the five cases, while "Boardman 2017" shows the highest worst-case average.

Figure 12-8: Average NPVRR of Four Worst Futures



Similar results are shown in Figure 12-9 for the selected portfolios when looking at the TailVar analysis. Here again "Diversified Green with On-peak Energy" shows the lowest value, just over $28 billion. The early Boardman closure portfolios all have higher TailVar scores – with the earlier the closing, the worse the outcome.

Figure 12-9: Stochastic Risk - TailVar

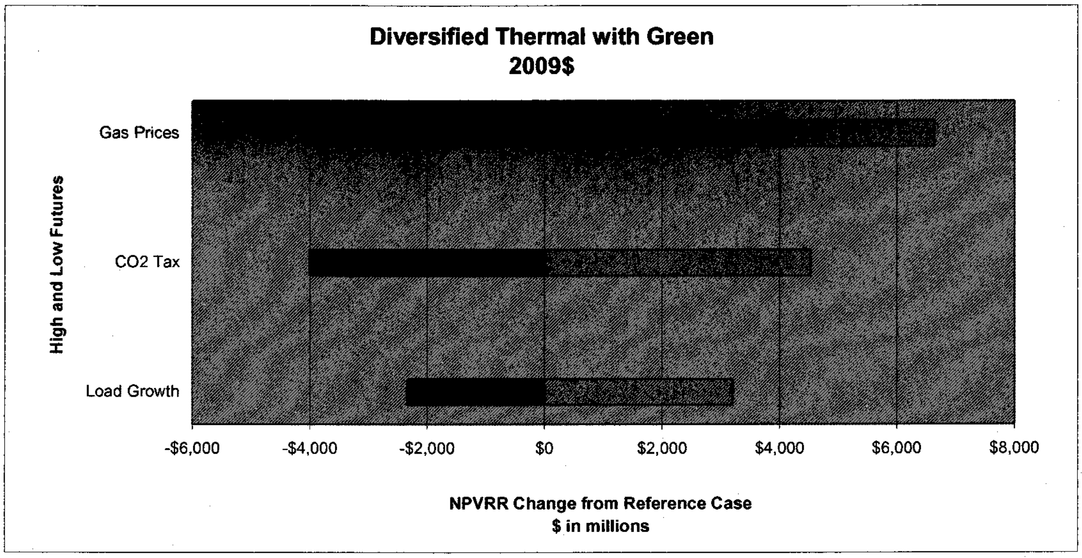


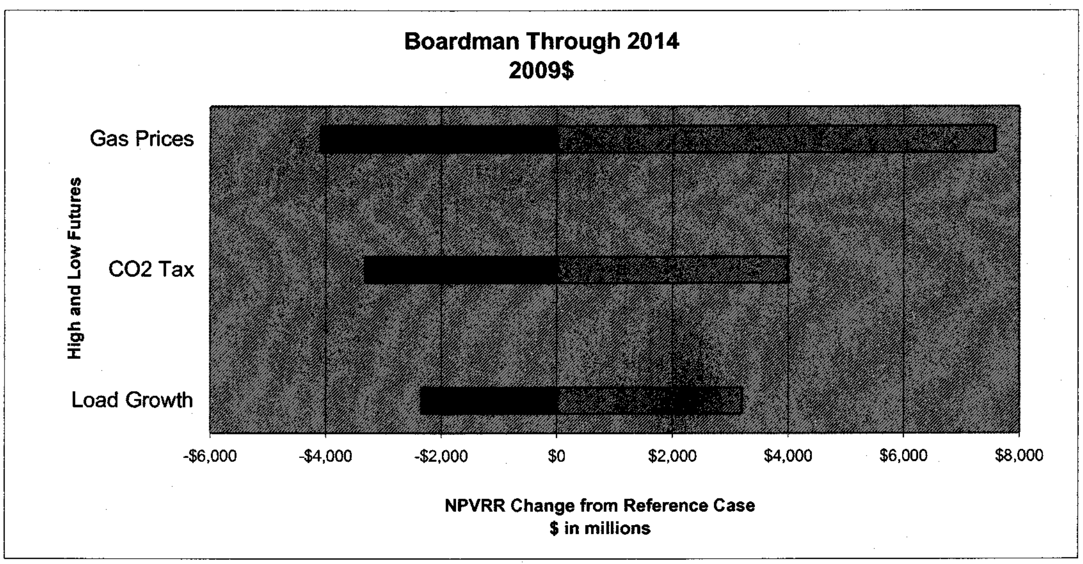
Primary Drivers of Uncertainty

Portfolios were stress-tested with several discrete futures. Of all the futures tested, variation in natural gas price, CO_2 price and load growth had the most impact on our portfolio NPVRR. Natural gas price was modeled with low, reference and high price futures at $5.19, $7.86 and $12.84 (real levelized 2009$) respectively. CO_2 prices ranged from $0 per short ton to $65 per short ton with a reference price at $30 (real levelized 2009$) and non-EE adjusted load growth rates were modeled at 1.21% and 2.72% per year for low and high scenarios with a reference growth rate at 1.91%.

Figure 12-10 shows the "Diversified Thermal with Green" and "Boardman Through 2014" portfolios' sensitivity to these futures. "Boardman Through 2014" is more exposed to gas price risk than "Diversified Thermal with Green." This portfolio assumes a CCCT as the replacement technology for Boardman past 2014. "Boardman Through 2014" has an expected NPVRR change from the reference case gas price of $7.582 billion compared to $6.636 billion for "Diversified Thermal with Green". For the same magnitude of natural gas price increase (from $7.86 to $12.84, both real levelized in 2009$), "Boardman Through 2014" has an NPVRR of $946 million more than "Diversified Thermal with Green."

Figure 12-10: Boardman Portfolios' Sensitivity to Gas Prices





"Diversified Thermal with Green" is more exposed to CO_2 risk. This reflects the higher CO_2 output profile of a coal plant compared to a CCCT. Exposure to CO_2 price is $4.526 billion for "Diversified Thermal with Green" and $4.003 billion for "Boardman Through 2014". Exposures to load growth are identical at $3.199 billion for downside and $2.345 billion on the upside for both portfolios.

Another insight from these graphs is the apparent asymmetry between upside and downside exposure to gas price risk, while CO_2 price and load growth have fairly balanced risk profiles. For "Diversified Thermal with Green" and

"Boardman through 2014," upside and downside of portfolio NPVRR for CO_2 price risk are +$4.526 vs. -$4.002 and +$4.003 vs. -$3.312 billion respectively. But for gas price risk exposure, the range is +$6.636 vs. -$3.662 and +$7.582 vs. -$4.076 respectively for those portfolios. This reflects the asymmetry of the high and low natural gas prices as compared to the reference case price. Most natural gas price forecasts (including PGE's) indicate that there is more risk that prices will rise rather than fall; this is a logical deduction with a log-normally distributed price.

Of the three major cost drivers, natural gas price risk emerges as the greatest driver of the portfolio NPVRR and as a result, the single largest risk factor. CO_2 price is second and load growth is third. Load growth risk magnitude is identical for both portfolios. "Diversified Thermal with Green," though more exposed to CO_2 risk, performs better under a high gas price future than "Boardman Through 2014."

12.6 Assessing Boardman Analytical Results

The portfolio analysis, using both scenario and stochastic approaches, provides a comprehensive look at Boardman's value and risks. PGE's recommendation takes into account expected cost, as well as price and reliability risk. Overall, "Diversified Thermal with Green" scored better than the Boardman 2014 portfolio – see Table 12-1 below. The "Diversified Thermal with Green" portfolio which includes Boardman through 2040 also clearly outperformed the early closure cases with respect to price risk and reliability. In general, although more exposed to CO_2 costs, the "Diversified Thermal with Green" portfolio provides an effective hedge against natural gas price volatility, while maintaining system reliability at a relatively low cost.

Table 12-1: Boardman Portfolio Analysis Scoring Grid

	1. Portfolio Evaluation Scoring: Raw Performance Metrics	Screening		Deterministic						Stochastic			Reliability & Diversity		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Zone?	Meets Operating Reserve Req?	Cost: Expected Cost Reference Case	Prob. of Poor Perf.	Prob. of Good Perf.	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variance	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
	Units	Y or N	Y or N	$ NPV Million	%	%	%	$ NPV Million	$ NPV Million	$ NPV Million	$ NPV Million	Trillion	MWa	Points	Points
8	Green w/ On-peak Energy Target	Y	Y	$ 28,971	0%	19%	19%	$ 33,993	$ 5,023	$ 28,136	$ 6,937	21.7	474.0	2670	1582
9	Diversified Thermal with Green	Y	Y	$ 28,674	5%	71%	67%	$ 34,910	$ 6,236	$ 30,631	$ 7,280	21.1	492.3	2923	1942
10	Boardman through 2014	Y	Y	$ 28,593	5%	81%	76%	$ 35,126	$ 6,533	$ 31,727	$ 8,406	25.7	522.7	3718	2031
12	Boardman through 2011	Y	Y	$ 28,777	10%	10%	0%	$ 35,247	$ 6,470	$ 31,827	$ 8,315	24.4	498.4	3718	2112
15	Boardman through 2017	Y	Y	$ 28,780	10%	10%	0%	$ 35,257	$ 6,477	$ 31,670	$ 8,200	24.5	505.7	3718	1970

	2. Portfolio Evaluation Scoring: Normalized Scores (0 to 100)	Screening		Deterministic				Stochastic			Reliability & Diversity		
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Zone?	Meets Operating Reserve Req?	Cost: Expected Cost	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variance	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
8	Green w/ On-peak Energy Target	Y	Y	68.1	64.1	100.0	78.6	90.7	53.1	61.2	88.1	68.8	95.7
9	Diversified Thermal with Green	Y	Y	73.5	89.7	80.3	54.3	40.1	40.7	64.9	83.6	52.2	35.2
10	Boardman through 2014	Y	Y	75.0	94.9	75.6	48.3	17.9	0.0	36.4	76.1	0.1	20.1
12	Boardman through 2011	Y	Y	71.7	53.8	73.0	49.6	15.9	3.3	44.1	82.1	0.1	6.5
15	Boardman through 2017	Y	Y	71.6	53.8	72.8	49.5	19.0	7.5	44.0	80.3	0.0	30.4

	3. Portfolio Evaluation Scoring: Total Weighted Scores	Screening		Deterministic				Stochastic			Reliability & Diversity					
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	[illegible]	[illegible]
	Scoring Consideration	Within Efficient Zone?	Meets Operating Reserve Req?	Cost: Expected Cost	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variance	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI	Weigted Combined Score (0 to 100)	[illegible]	[illegible]
	Weight			50%	10%	5%	5%	3.3%	3.3%	3%	15%	3%	3%			
8	Green w/ On-peak Energy Target	Y	Y	34.1	6.4	5.0	3.9	3.0	1.8	2.0	13.2	1.7	2.4	73.6	[illegible]	[illegible]
9	Diversified Thermal with Green	Y	Y	36.8	9.0	4.0	2.7	1.3	1.4	2.2	12.5	1.3	0.9	72.0	[illegible]	[illegible]
10	Boardman through 2014	Y	Y	37.5	9.5	3.8	2.4	0.6	0.0	1.2	11.4	0.0	0.5	66.9	[illegible]	[illegible]
12	Boardman through 2011	Y	Y	35.8	5.4	3.6	2.5	0.5	0.1	1.5	12.3	0.0	0.2	61.9	[illegible]	[illegible]
15	Boardman through 2017	Y	Y	35.8	5.4	3.6	2.5	0.6	0.2	1.5	12.0	0.0	0.8	62.5	85%	[illegible]

Other Considerations

There are other considerations that are not captured in our IRP portfolio scoring but are relevant to the decision to invest in emissions controls at Boardman. These considerations favor keeping the plant open through 2040.

As of this writing, if and when climate legislation is adopted by the Congress, it appears that the most likely policy outcome is legislation that resembles the Waxman-Markey bill. Legislation introduced in the Senate by Senators Kerry and Boxer (S. 1733) on September 30, 2009 resembles Waxman-Markey in several respects. Preliminary analysis of the September 30 version of S.1733 conducted by EPA (published October 23, 2009) suggests that the economic impacts of the bills will be similar, with S.1733 resulting "sight" or "small" allowance price increases due to differences in the bill provisions affecting the 2020 cap levels, offset limits, strategic reserve, EE and renewable energy provisions and the CCS bonus allowances. However, in order for the Senate to secure 60 votes for cloture, additional negotiation and compromise can be expected including the possibility of adding a firm price collar for allowances.PGE's current reference case price is $30 per short ton. The PGE reference case price is a composite of EPA and EIA studies of legislative proposals and includes the EPA work on Waxman-Markey. PGE's approach to assessing CO_2 risk and selecting a reference case price is described in greater detail in Chapter 6. Although the CO_2 price is unknown at this point, ongoing discussions in the Senate about a price collar mechanism could further diminish the probability of a higher CO_2 price.

In addition, it is reasonable to expect that operational changes and/or technology advancements will affect CO_2 reductions for coal-fired plants. These may include biomass co-firing, biogenic CO_2 capture and recycling, and CO_2 capture with geologic sequestration. PGE's algae sequestration pilot project (described in Chapters 6 and 7) is a promising example. Improvements in CO_2 abatement technology do not need to be specific to Boardman in order to benefit Boardman economics. If development in such technology is accelerated due to an increase in policy-based incentives, even if only available in other parts of the country, PGE's customers will benefit from such incentives since they would likely affect CO_2 prices. Furthermore, the availability of international offsets could put further downward pressure on CO_2 prices.

Boardman Recommendation

With respect to Boardman emissions controls investments and the future operations of the plant, the choices left to us as a result of the Oregon Regional Haze Plan and Utility Mercury Rule are not optimal for our customers compared to the other options that PGE proposed to the DEQ in its Decision Point Plan. In addition, the process of evaluating whether or not to invest in emissions controls is both complex and challenging. As discussed above, however, non-compliance with the Oregon Regional Haze Plan and Oregon Mercury rule is not an alternative. We must also keep in mind that an appropriate course of action for Boardman must be consistent with the objectives of the IRP - that is, to identify a resource action plan, that when considered with our existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for the utility and its customers. Given these goals, we recommend compliance with the Oregon Regional Haze Plan and Oregon Mercury Rules in two phases:

Phase 1

- NOx Controls: install the LNB/MOFA control system which, as proposed, is estimated to reduce NOx by 4,000 tons per year, for a 46% reduction compared to current emission levels. These controls will be installed by July 2011 to meet the 0.28 lb/MMBtu (30-day rolling average) and 0.23 lb/MMBtu (12-month rolling average) emissions limit. The estimated overnight capital cost is $33 million (100% of Boardman plant). Engineering Procurement and Construction (EPC) work will start in early 2010 to support the July 2011 schedule. We anticipate that it will not be necessary to request a compliance extension, thereby changing the dual limits to a single 0.23 lb/MMBtu (30-day rolling average) emissions limit.

- Mercury Controls: install the mercury (Hg) control system by 2012 for an estimated overnight capital cost of $7.7 million (100% of Boardman plant).

- SO_2 Controls: install scrubbers, which will cut SO_2 emissions by 12,000 tons per year for an 80% reduction compared to current emission levels. These controls will be installed by July 2014 to meet the 0.12 lb/MMBtu 30-day average emissions limit.

- Particulate Matter Controls: install a pulse jet fabric filter as part of the scrubber installation to supplement the existing electrostatic precipitator. This installation will cut particulate matter emissions by 122 tons per year for a 29% reduction from current levels. These controls will be installed by July 2014 to meet the 0.012 lb/MMBtu emissions limit. The particulate matter controls, together with the scrubbers, are estimated to have overnight capital cost of $289.9 million (100% Boardman plant).

Phase 2

- NOx Controls: install Selective Catalytic Reduction (SCR), which will cut NOx emissions by an additional 4,000 tons per year for an additional 38% reduction, beyond the Phase I upgrades. These controls will be installed by July 2017 to meet a 0.070 lb/MMBtu emissions limit for an estimated overnight capital cost of $180 million (100% Boardman plant).

Table 12-2 below provides the dates by which equipment must be installed in order for PGE to meet its compliance obligations. An all inclusive engineering, procurement and construction (EPC) approach is preferred, except for the Hg controls. Delay in meeting contract dates will correspondingly delay the date when equipment is operational and the plant can operate in compliance with the Oregon Regional Haze Plan and Oregon Mercury Rule.

Table 12-2: Boardman Engineering Procurement and Construction Schedule

	Controls	EQC Emission Compliance Date	EPC Contract Date
1.	LNB/OFA	July 2011	Feb 2010
2.	Mercury	July 2012	Q2-2011
3.	FGD	July 2014	Q1-2011
4.	SCR	July 2017	Q1-2014

Table 12-3 below summarizes the capital costs associated with each of the DEQ's recommended emissions controls; capital costs in this table are for 100% of the Boardman plant output. Installation of the new systems is expected to take place during our normally scheduled spring maintenance outages.

Table 12-3: Boardman Emissions Controls Capital Costs, Nominal $

	LNB/OFA		Hg/FGD		SCR		Total	
2007	$	75	$	100	$	75	$	250
2008	$	468	$	624	$	468	$	1,560
2009	$	1,554	$	376	$	77	$	2,007
2010	$	16,628	$	3,785	$	116	$	20,529
2011	$	14,123	$	85,862	$	94	$	100,079
2012	$	-	$	127,146	$	116	$	127,262
2013	$	-	$	58,570	$	684	$	59,254
2014	$	-	$	21,042	$	38,789	$	59,831
2015	$	-	$	-	$	80,564	$	80,564
2016	$	-	$	-	$	43,720	$	43,720
2017	$	-	$	-	$	15,350	$	15,350
Overnight Capital	**$**	**32,848**	**$**	**297,505**	**$**	**180,053**	**$**	**510,406**
AFDC	$	3,636	$	73,627	$	42,352	$	119,615
Property Tax	$	386	$	9,913	$	5,727	$	16,026
Total	**$**	**36,870**	**$**	**381,045**	**$**	**228,132**	**$**	**646,047**

With all controls in place in 2017, total fixed and variable O&M for PGE's 65% share of Boardman is projected to increase by approximately $8.1 million in 2009 $. About two-thirds of this amount is variable O&M. At the same time, the net plant heat rate is projected to increase by about 2% and plant output is projected to decrease by the same percentage. The ongoing impacts to the dispatch cost due solely to emissions controls (the variable O&M and change in heat rate) are fairly modest. In 2017, when all controls are in place, the dispatch cost is expected to increase by approximately $3 per MWh in 2009 $ exclusive of CO_2 costs.

This analysis is based on PGE's cost of capital. Tax-favored pollution control bond financing, if available, could improve the economics. Our modeling assumes no extension of the Oregon Pollution Control Facilities Tax Credit program, which currently does not benefit controls that were placed in service after December 31, 2007.

The PGE Power Supply Engineering Services group and the Boardman plant operations team are comfortable in this assessment of expected plant life and believe it may, in fact, be conservative. There are many instances of thermal plants operating well beyond their original book life and Boardman has a number of relatively new major components or upgrades, including steam turbines, pulverizers and boiler tubing. Other scheduled replacements over the next few years include generator components and burners.

In summary, PGE recommends proceeding with the Phase 1 and 2 emissions control upgrades required under the Oregon Regional Haze Plan and the Oregon Utility Mercury Rule, and retaining Boardman in our resource portfolio. This recommendation is based on the results of our portfolio analysis, which indicate that the portfolio which includes the operations through 2040, and the portfolio that ceases plant operations in 2014 yield similar expected cost results. However, the 2040 Boardman portfolio performs better across most risk metrics, including price risk and reliability measures. The Boardman 2040 portfolio also provides for increased fuel and technology diversity when compared to the early shutdown cases. Further details regarding the results of our portfolio analysis can be found in Chapter 11. Because of the importance of Boardman to PGE's resource portfolio and the significant adverse consequences that would result if PGE were not to comply with the Oregon Regional Haze Plan and Oregon Mercury rule, it is imperative that the Commission act promptly in its review of PGE's Integrated Resource Plan.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-18

IDAHO POWER COMPANY

ATTACHMENT NO. 2

12A. Boardman Analysis

Boardman, a pulverized-coal plant located in north-central Oregon, is a key resource for PGE and our customers. It is a low-cost, baseload plant that enables us to provide 15% of our customers' energy needs with a stable fuel source and also contributes to the diversity of our supply mix. Boardman is in the top quintile among U.S. coal plants for efficiency (heat rate) in converting fuel to electricity. Because Boardman has been well maintained, it is expected to have continued reliable and efficient operations for the foreseeable future.

In this chapter we describe the emissions controls required under the recently adopted Oregon Regional Haze Plan and the Oregon Utility Mercury Rules. We also present a new emissions control and operating plan which PGE has proposed in a petition to amend the existing Oregon Regional Haze Plan filed with the Oregon Department of Environmental Quality (DEQ) on April 2, 2010 (BART II Petition). This new plan is incorporated via our "Boardman through 2020" portfolio, which forms the basis of our preferred Action Plan. This chapter also provides detailed analysis of the different cases for Boardman emissions controls and operations, including PGE's new proposal to implement a more limited controls package in conjunction with a plan to cease coal-fired operations at the plant in 2020.

Our analysis of the "Boardman through 2020" portfolio balances several important objectives, including cost and risk for customers, system reliability, meeting state and federal emissions standards, and reducing the impact of electric generation on the environment. The portfolio also allows for an orderly transition to replacement supply sources and reduces the impact of a change in plant operations on affected communities and employees. The "Boardman through 2020" portfolio is our preferred portfolio. However, as described in detail in Chapter 13A, implementation of the "Boardman through 2020" portfolio is dependent on the resolution of certain contingencies. Given the reliability and cost risk to customers of a 2014 plant closure, as discussed later in this chapter,[9] we are asking the Commission to acknowledge that is prudent for us to proceed with an alternate Action Plan based on the Diversified Thermal with Green portfolio (with or without lease), which continues Boardman operations through 2040 if contingencies are not resolved by March 31, 2011. The details of both our preferred and alternate plans for Boardman are presented in the balance of this chapter and in Chapter 13A.

[9] In particular, refer to the discussions immediately after Figure 12A-1 and prior to Figure 12A-5.

Chapter Highlights

- PGE proposes a new Boardman BART / Regional Progress plan (BART II). Under the new, proposed plan PGE would install a more limited emissions control upgrade package in conjunction with ceasing coal-fired operations at the plant in 2020.
- This chapter provides comparative analysis of the proposed new Boardman 2020 plan to other potential cases for Boardman.
- Our analysis indicates that a Boardman through 2020 portfolio provides the best combination of cost and risk for customers, when compared to other viable cases. This portfolio is the basis for our preferred Action Plan.
- If we are not able to implement the Boardman through 2020 portfolio, the next best alternative for PGE customers is the Diversified Thermal with Green portfolio. This portfolio is the basis for our alternate Action Plan.
- The detailed elements of our preferred and alternate plans for Boardman are presented below and in Chapter 13A.

12A.1 Oregon Regional Haze Plan

As part of the implementation of the Federal Clean Air Act section 169A, the Oregon Department of Environmental Quality (DEQ) issued a draft Oregon Regional Haze Plan that was later adopted by the Environmental Quality Commission (EQC) on June 19, 2009. The Oregon Regional Haze Plan requires the installation of environmental controls as Best Available Retrofit Technology (BART) at the Boardman plant for the purpose of reducing visibility-impairing emissions and additional environmental controls as Reasonable Progress (RP) towards additional haze causing emissions reductions.

In addition to the Oregon Regional Haze Rule, Boardman is also subject to the Oregon Utility Mercury Rule. PGE has received DEQ approval of a proposed approach whereby activated carbon is injected upstream of the existing electrostatic precipitator in possible combination with calcium halide additive on the coal. This approach is expected to result in the capture of 90 percent of the mercury contained in the flue exhaust gases, enabling the plant to meet the emissions standard under the Utility Mercury Rule. While this control approach increases the risk of rendering the fly ash unsellable, it provides an overall cost benefit to PGE customers by substantially decreasing mercury emissions while avoiding the installation of expensive fabric filter equipment.

12A.2 Current Regional Haze Plan Requirements

The current Regional Haze Plan requirements applicable to Boardman consist of two phases: Phase 1 BART controls; and Phase 2 RP controls. Phase 1 compliance requires installation of Low NOx Burner and Modified Over-Fire Air (LNB/MOFA) and semi-dry flue gas desulfurization (scrubbers) with an associated fabric filter. Phase 2 requires the installation of selective catalytic reduction (SCR). Under the existing Regional Haze Plan, PGE has the following options:

- Install all of the controls: LNB/MOFA by July 2011, scrubbers/fabric filter by July 2014 and SCR by July 2017 and operate Boardman through 2040 or beyond (modeled in the "Diversified Thermal with Green" portfolios).
- Install LNB/MOFA and scrubber/fabric filters and cease Boardman operations in 2017; do not make the SCR investment (modeled in the "Boardman through 2017" portfolio).
- Install LNB/MOFA only and cease Boardman operations in 2014 (modeled in the "Boardman through 2014" portfolio).
- Cease Boardman operations in July 2011 with no obligation to install additional controls (modeled in the "Boardman through 2011" portfolio).

12A.3 BART II

On April 2, 2010, PGE submitted a Petition to amend the Oregon Regional Haze Rule to the DEQ (BART II Petition). This BART II Petition seeks changes to allow Boardman meet BART/RP requirements through an alternate proposal that utilizes a more limited emissions control upgrade package in conjunction with a change in the plant's operation and a commitment to cease coal-fired operations or shut down the plant in 2020. Under this proposed petition, PGE would cut haze-causing emissions of sulfur dioxide and nitrogen oxides from the Boardman plant by:

- Installing new, state-of-the-art LNB/MOFA burners by July 1, 2011. The new burners are expected to reduce nitrogen oxides emitted by the plant by nearly 50 percent.
- Using coal with a lower sulfur content to fire the plant's boiler. This would be completed in two stages as PGE's current coal supply contracts expire. In addition, PGE has recommended an initial 20 percent drop in permitted sulfur dioxide emissions that would take effect in 2011. This is followed by a further reduction in 2014 that would bring allowed sulfur dioxide emissions down by a total of 50 percent from current permit levels.

- Closing the plant in 2020, ending all coal-related emissions at least 20 years ahead of schedule and significantly reducing Oregon's contribution to green house gas emissions.

Under a separate rulemaking procedure with DEQ, PGE already has agreed to install controls that are expected to eliminate 90 percent of the plant's mercury emissions by 2012. Current construction schedules should allow PGE to meet this deadline a year early, in 2011.

Table 12A-1: Comparison of Existing vs. Proposed BART Rule

			Current Rule			Proposed BART II Revision		
Controls	*Constituent*	*2009 Emissions*	*Emissions**	*Cost***	*Schedule*	*Emissions**	*Cost***	*Schedule*
Low NOx Burners / OverFire Air	NOx	0.41	0.23	$32.8 Million	Jul-11	0.23	$32.8 Million	Jul-11
Dry Scrubber with Fabric Filter	SO2	0.70	0.12	$289 Million	Jul-14	Shut Down @ end of 2020		
	PM	0.17	0.012	(Incl. in above)	Jul-14	Shut Down @ end of 2020		
Reduced Sulfur Coal Restriction 1	SO2					0.96	Increased O&M	Dec-11
Reduced Sulfur Coal Restriction 2	SO2					0.60	Increased O&M	Jul-14
Selective Catalytic Reduction (SCR)	NOx		0.07	$180 Million	Jul-17	Shut Down @ end of 2020		
Mercury Controls	Hg		90%	$7.7 Million	Jul-12	90%	$7.7 Million	Jul-12
Aggregate Emissions (tons)			256,815			231,224		
Totals				$509.5 Million			$40.5 Million	
* Lbs/Mmbtu								
**Costs are nominal Capital dollars and do not include AFDC and property taxes								

The concept of potentially closing Boardman early was first introduced by the company in response to a December 1, 2008 DEQ proposed BART determination for the Boardman Plant Boiler. During the public comment period the company requested that DEQ consider allowing PGE to have options to forego certain controls if the company committed to cease operation of the Boardman Plant boiler by dates certain.

On June 19, 2009, the Oregon Environmental Quality Commission (EQC) adopted DEQ's proposed Oregon Regional Haze Plan which included extensive emission controls. Although the EQC did not adopt the company's proposal it did include in its adopted plan an express statement that "Should PGE determine that the impact and cost of carbon regulations will require the closure of the PGE Boardman plant, PGE may submit a written request to the Department for a rule change". In response to feedback from IRP stakeholders and further analysis of the EQC ruling, the company began analyzing a portfolio with a 2020 closure of the Boardman plant. Based on that feedback and analysis, as well as our belief that such a portfolio could meet the emissions standards required under the Regional Haze Program, PGE submitted the BART II request to DEQ.

While a DEQ schedule has not yet been established, the following is from the DEQ press release of April 2, 2010:

DEQ officials will study PGE's proposal and analysis to assess whether it adequately addresses all the factors needed to comply with federal regulations. If so, DEQ will begin a new rulemaking process that will provide the opportunity for the public to review and provide comment. Depending on the outcome of DEQ's review and public process it may be possible to bring a proposed rule revision to the EQC for consideration by the end of the year.

12A.4 Portfolio Analysis

Throughout the remainder of this chapter we focus on a set of portfolios that represent five distinct emission control upgrade and operating plan cases for Boardman. Four of the portfolios, "Boardman through 2011", "Boardman through 2014", "Boardman through 2017" and "Boardman through 2020" represent early closure scenarios. The fifth case, "Diversified Thermal with Green", represents a plan where all emissions controls required under the current DEQ rules are implemented at Boardman and the plant is retained in PGE's portfolio through 2040. Of the above portfolios, only "Boardman through 2020" represents a new case from those presented in PGE's November 2009 IRP filing. This new portfolio provides a Boardman capital and operating plan that is consistent with our BART II Petition. The "Boardman through 2020" portfolio includes the following primary elements:

- Installation of LNB/MOFA in 2011;
- The use of low sulfur coal to meet a 20% reduction in permitted SO_2 emissions by the end of 2011;
- Injection of carbon to eliminate 90 percent of the plant's mercury emissions by 2012;
- The use of low sulfur coal to meet a 50% reduction in permitted SO_2 emissions by July 2014;
- Cessation of coal-fired operations of Boardman at the end of 2020;
- No further emissions control investments;
- Replacement of Boardman with a CCCT at the beginning of 2021.

In addition to the above components, please see Chapter 10A, section 10A.4, for a detailed description of the portfolio composition.

12A.5 Results of Portfolio Analysis

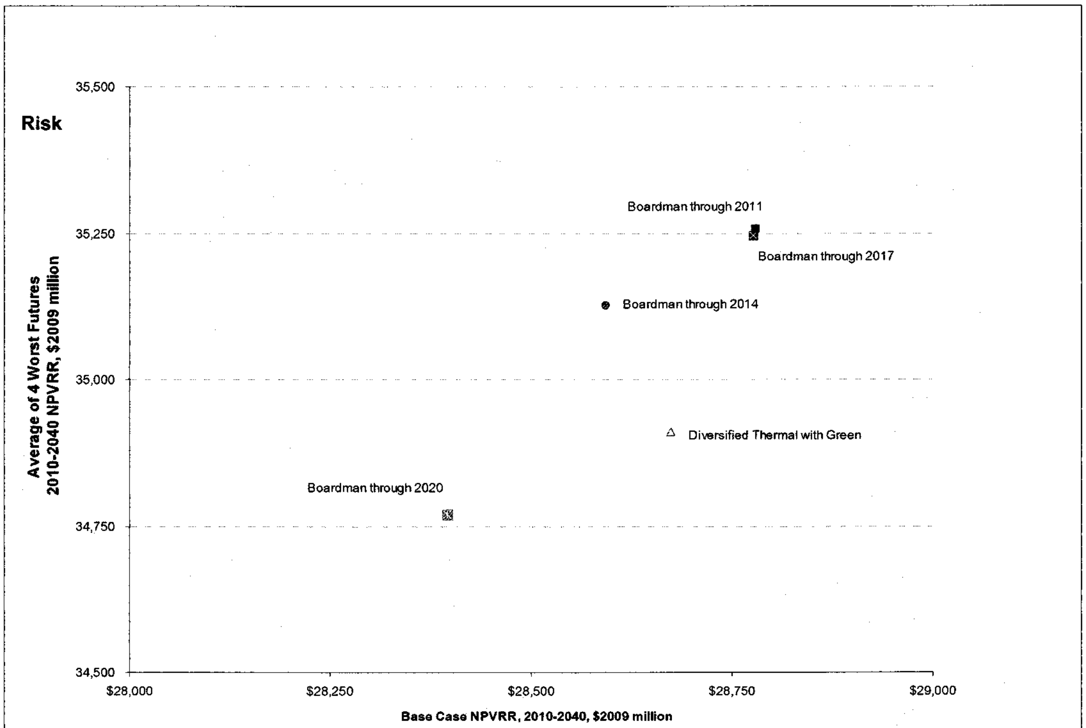
Please refer to Chapter 10A for a detailed description of our portfolio analysis approach.

Deterministic Portfolio Analysis Results

The Trade-off between Expected Cost and Associated Risk

Portfolios with a lower level of risk for a given amount of cost (or vise versa) are deemed to be efficient. This is visually represented on an Efficient Frontier graph where efficient portfolios are closest to the origin when plotting expected costs (plotted on the X-axis) and portfolio risk (plotted on the Y-axis) measured by the average NPVRR of the four worst futures. We originally presented an Efficient Frontier graph in Figure 12.1 of our initial IRP. When the "Boardman through 2020" portfolio is added to the graph, as illustrated in Figure 12A-1, it becomes the best performer. This is a result of the fact that the "Boardman through 2020" provides a better trade-off between cost and risk than any of the other four portfolios. Following "Boardman through 2020", "Diversified Thermal with Green" and "Boardman through 2014" provide the next best cost and cost risk performance. However, "Boardman through 2014" also poses increased implementation and replacement supply risk that is not reflected in the Efficient Frontier Graph.

Figure 12A-1: Efficient Frontier for Boardman Portfolios



This graph also demonstrates that "Boardman through 2020" outperforms the other 4 portfolios on both expected cost and risk, by $197 million in expected cost and $356 million in cost risk compared to the next best early closure portfolio, "Boardman through 2014".

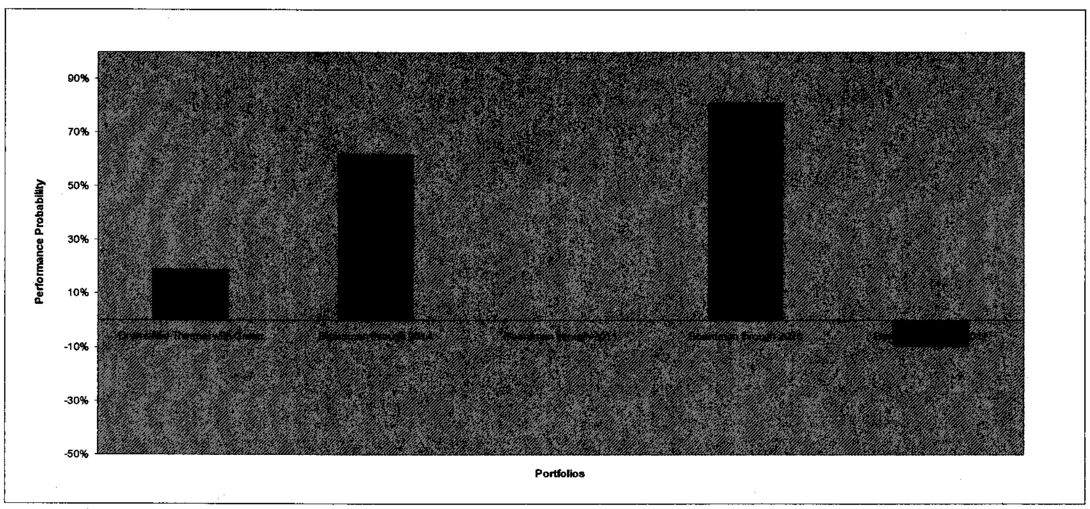
Portfolio Durability: Combined Probability of Achieving Good and Avoiding Bad Outcomes

Although the deterministic approach to portfolio analysis does not assign probabilities to the likelihood of a particular future taking place, one way to look at portfolio durability is to count the frequency of good outcomes vs. bad outcomes. Our IRP analysis defines a bad outcome as the number of times that a given portfolio ranks among the worst four out of the 16 candidate portfolios we tested across 21 futures. And conversely, a good outcome is defined as the number of times that a given portfolio ranked among the best four out of the 16 portfolios we tested across 21 futures. The goal is to avoid bad outcomes while seeking good outcomes.

Better portfolios have a high probability of *combined* good vs. bad outcomes. In our scoring, a portfolio that always ranked in the top four would get a 100% score, a portfolio that always ranked in the bottom four would get a -100%. Mediocre portfolios that had mixed results would score closer to 0%.

"Boardman through 2020" again outperforms the other four portfolios in this metric - 81% of the time it is in the top four performing portfolios through the 21 futures it was tested against.

Figure 12A-2: Combined Probability of Good and Bad Outcomes for Boardman Portfolios



Scenario Risk Magnitude

Scenario (deterministic) risk is measured by two metrics; (1) the average NPVRR of the four worst futures, and (2) the average NPVRR of the four worst futures less the reference case. The first metric addresses the potential magnitude of adverse outcomes. The second metric measures the extent to which performance could adversely change from the expected case. Performance according to the first scenario risk metric is described above under the discussion regarding the trade-off between risk and cost. Looking at the second of these two metrics, "Diversified Thermal with Green", which retains Boardman through 2040, performs best when compared to the other four Boardman alternatives.

Our portfolio scoring includes three measurement categories from the deterministic portfolio analysis: Expected Cost, Risk Durability and Risk Magnitude (Risk Magnitude includes Average of the four worst cases, as well as Average of the four worst cases vs. Reference Case). In total, these deterministic risk measures comprise 70% of the overall portfolio score (see Table 12A-2). "Boardman through 2020" performs best according to the combined deterministic risk measures when compared to the other four Boardman alternatives presented in this chapter.

Stochastic Portfolio Analysis Results

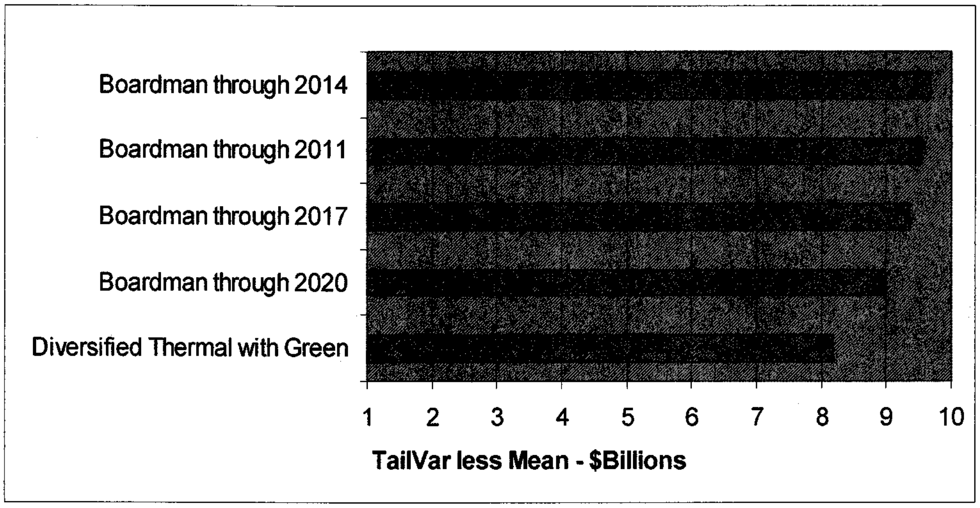
By stochastically modeling WECC-wide load, natural gas prices, historic water years, plant forced outages and the intermittency of wind production, we were able to assess probabilistic metrics of Boardman portfolio risks. As detailed in Chapter 10A, the portfolios were run 100 times subject to stochastic variations in the above variables. For stochastic analysis, we employ a NPVRR TailVar less Mean to look at portfolio risk over our dispatch modeling horizon of 2010 to 2040, as well as a year-to-year variability metric.

TailVar 90 less Mean:

This metric measures the right-tail risk or *magnitude* of bad outcomes for each individual portfolio, as measured by averaging the portfolio NPV that resides in the most expensive 10% of the distribution (right tail risk) and subtracting from this the portfolio mean NPV (i.e., expected cost). The result is a measure of how widely a portfolio can deviate from its expected cost.

The "Diversified Thermal with Green" portfolio outperforms the other Boardman alternatives by more than $1.2 billion on average. These results show the increased risk exposure when moving from coal as a fuel to a greater concentration of natural gas, which has more volatile prices.

Figure 12A-3: Stochastic Risk – TailVar less Mean for Boardman Portfolios

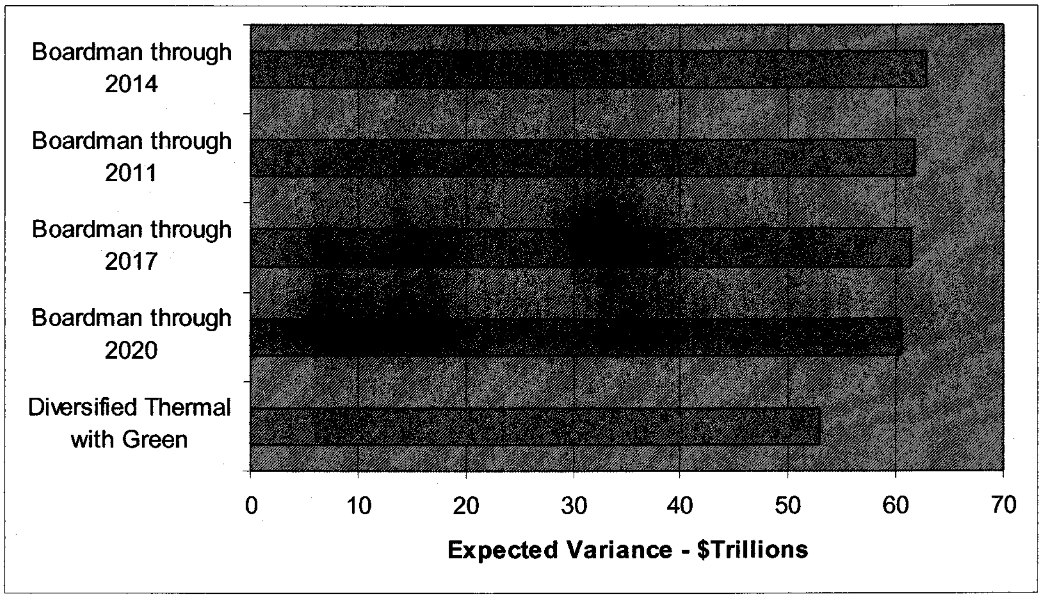


Stochastic Year-to-Year Variation

This metric addresses the innate volatility of a given portfolio. It measures the average year-over-year variation, based on 100 independent iterations of the stochastic inputs. While the "TailVar less mean" measures the worst 10% possible outcomes of the expected portfolio costs over the 31 forecast years, the "Year-to-Year Variation" metric measures changes in year-to-year portfolio costs. In other words, "TailVar less Mean" measures "how bad can the worst outcomes be?" over the life of the portfolio while "Year-to-Year Variation" measures "how bumpy is the road?" for a particular portfolio.

The best portfolio would have the lowest year-to-year variation. As shown in Figure 12A-4 below, "Diversified Thermal with Green" outperforms the other Boardman portfolios. "Boardman through 2020" is the next best performing portfolio according to this risk metric.

Figure 12A-4: Stochastic Risk – Year-to-Year Variation for Boardman Portfolios



Summary of Results from Stochastic Measures

We included three metrics from stochastic analysis in our portfolio scoring methodology: TailVar, TailVar less Mean and Year to Year Variation. Stochastic measurements comprised 10% of the total combined score (see Table 12A-2). Again, the "Diversified Thermal with Green" portfolio performs materially better than the other Boardman cases when considering stochastic cost risk.

Reliability and Diversity Analysis Results

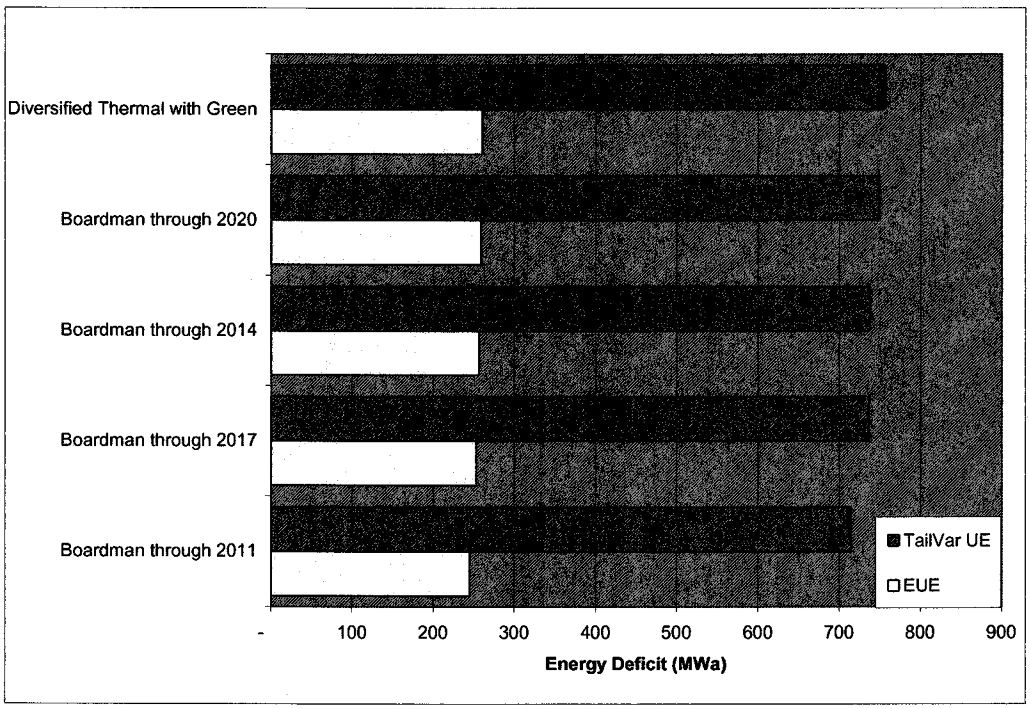
Tailvar Unserved Energy

We calculate the Tailvar of Unserved Energy (Tailvar UE) as the average of the worst 10% of outcomes (across 100 iterations where PGE's plants are subject to random forced outages and associated mean times to repair) where PGE must purchase power on the spot market in order to meet customer load. Expressed in MWa, market purchases are required when PGE's owned and contracted resources are insufficient to meet customer demand. This metric is calculated as the average for all years from 2010 through 2020, plus 2025. The higher the amount, the less reliable that portfolio is relative to the other portfolios.

According to the TailVar UE and EUE metrics "Boardman through 2011" has the highest reliability – see Figure 12A-5. This is largely due to two factors; (1) our model inputs assume a higher forced outage rate for Boardman than a CCCT replacement, and (2) the 2011 portfolio includes a bridge PPA with a forced outage rate equal to a CCCT. However, the TailVar UE and EUE results across the five portfolios presented in Figure 12A-5 are relatively small, with little overall difference in reliability performance for these cases.

It should also be noted that this analysis does not consider reliability risk associated with securing replacement supply sources. It only assesses relative reliability performance of candidate portfolios once all resources are procured and in place. Accordingly, the TailVar UE and EUE metrics do not include uncertainty and potential timing problems with respect to replacing a large current source of baseload energy and capacity such as Boardman. If PGE is unable to secure adequate replacement supply by the time Boardman is closed, our reliability risk would increase. For the earliest Boardman closure portfolios, "Boardman through 2011" and "Boardman through 2014" the replacement supply risk is much higher and more tangible due to the short amount of time that PGE would have to build or procure replacement resources.

Figure 12A-5: Unserved Energy Metrics for Boardman Portfolios, 2012-2020 & 2025



Technology and Fuel Diversity

PGE has applied the Herfindahl-Hirschman Index (HHI), which has traditionally been used to measure concentration of commercial market power. In this case, the HHI is used to measure the portfolio concentration in technologies and fuels (coal, natural gas, hydro, wind, market purchases, etc.) from 2010 through 2021.

A lower value means less portfolio concentration in any given technology or fuel type over the period. A lower HHI value is preferred as it indicates higher portfolio diversity and thus less exposure to specific fuel and generation technology driven risks.

The diversified portfolios outperform all of the early Boardman closure portfolios from fuel and technological perspectives. See Figure 12A-6 and Figure 12A-7 below respectively. While the early Boardman closure portfolios are equivalent on a technological basis, the later closures perform better from a fuel diversity perspective.

Figure 12A-6: Herfindahl-Hirschman Index Boardman Fuel Results

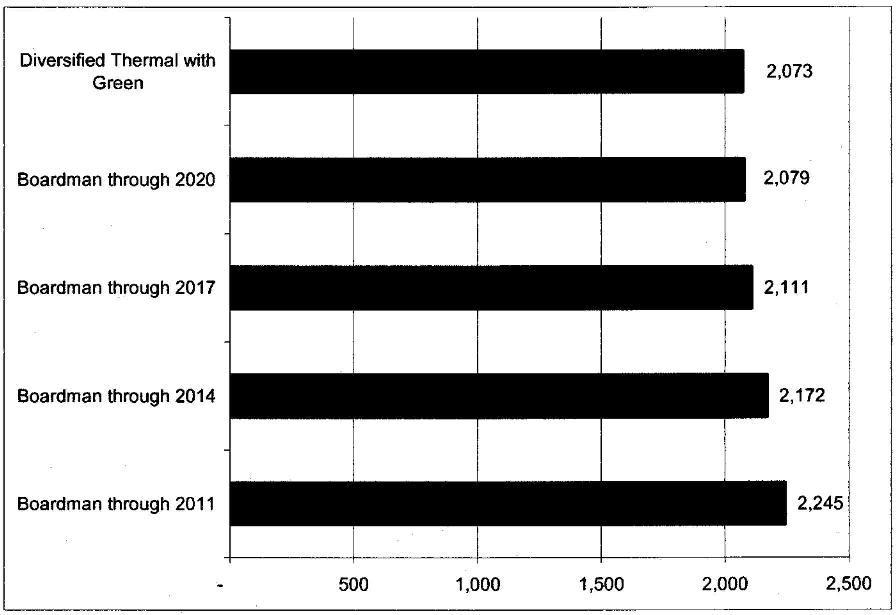
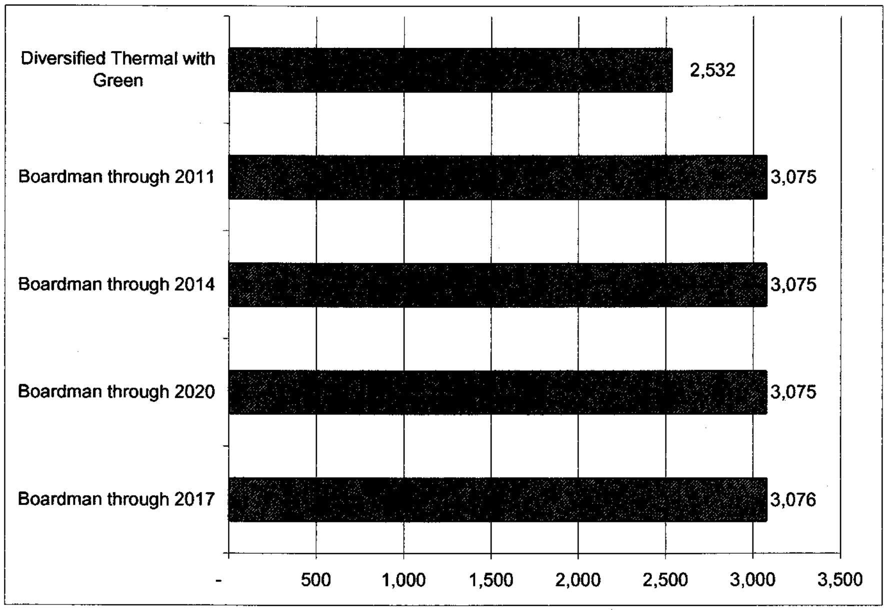


Figure 12A-7: Herfindahl-Hirschman Index - Boardman Technological Results



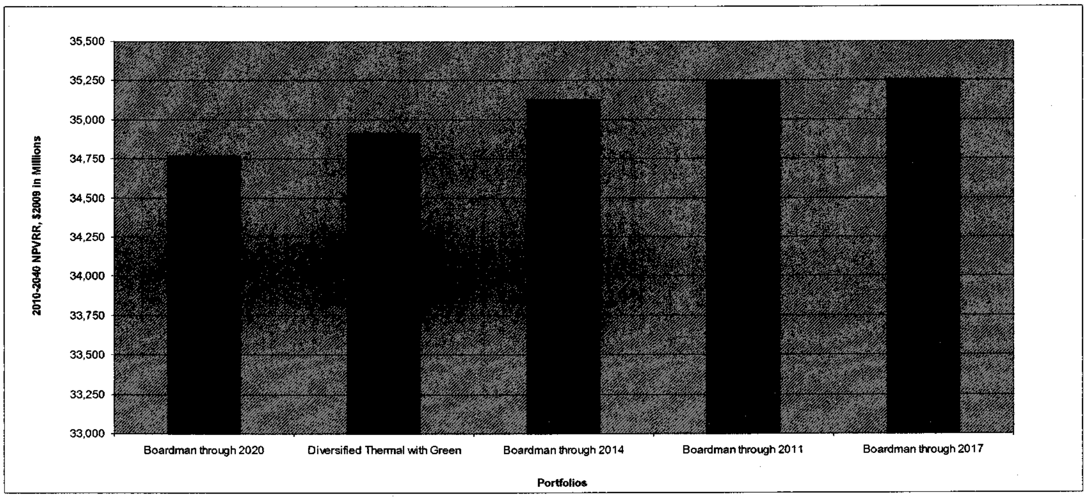
Summary of Results from Reliability and Diversity Measures

Our portfolio scoring includes three measurement categories from the reliability and diversity analysis: Tailvar UE, Technology HHI and Fuel HHI. Reliability and Diversity measures comprise 20% of the total score (see Table 12A-2). "Diversified Thermal with Green", which includes Boardman through 2040, performs better than the other four Boardman portfolios in the combined areas of Reliability and Diversity.

Other Metrics

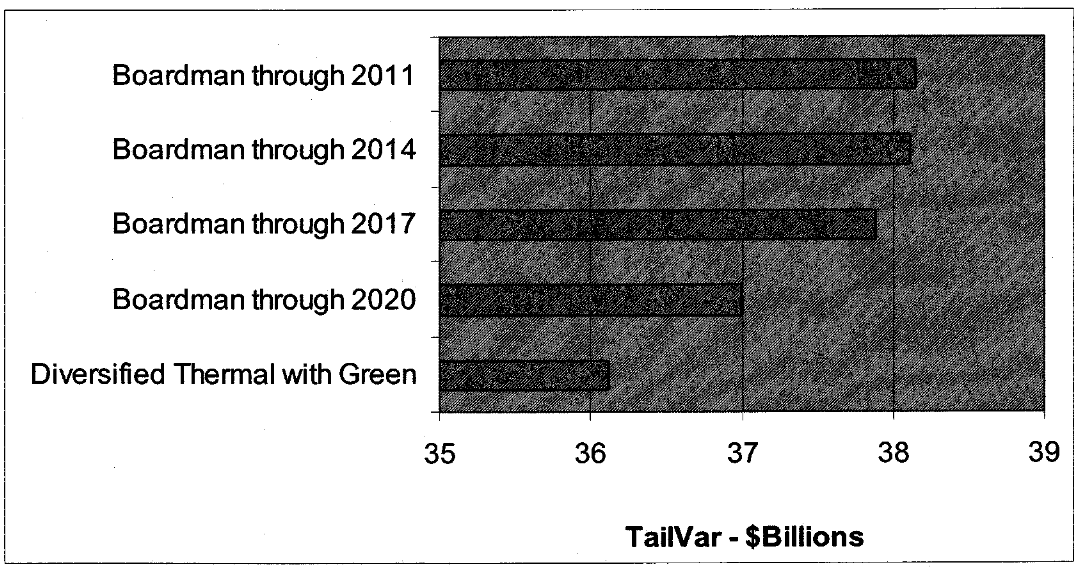
At the suggestion of OPUC Staff, PGE added a variation of two cost risk metrics described above to its scoring. Rather than look solely at the deterministic average of the worst four futures less the reference case cost and the similar stochastic metric of TailVar 90 less the Mean, we have added two right-tail metrics that provide absolute measurements of cost without subtracting a mean or reference case value. This allows for an absolute look at risk exposure without being influenced by distance from the mean. Figure 12A-8 shows the average NPVRR for the four worst future outcomes. "Boardman through 2020" has the lowest NPVRR of the five cases.

Figure 12A-8: Average NPVRR of Four Worst Futures



Similar results are shown in Figure 12A-9 for the selected portfolios when considering TailVar analysis. Here "Diversified Thermal with Green" shows the lowest value. The early Boardman closure portfolios all have higher TailVar scores – with earlier closure dates performing progressively worse.

Figure 12A-9: Stochastic Risk - TailVar



Primary Drivers of Uncertainty

Portfolios were stress-tested with several discrete futures. Of all the futures tested, variation in natural gas price, CO_2 price and load growth have the largest impact on portfolio NPVRR. Figure 12A-10 shows the "Diversified Thermal with

Green", "Boardman Through 2014" and "Boardman Through 2020" portfolios' sensitivity to these cost drivers.

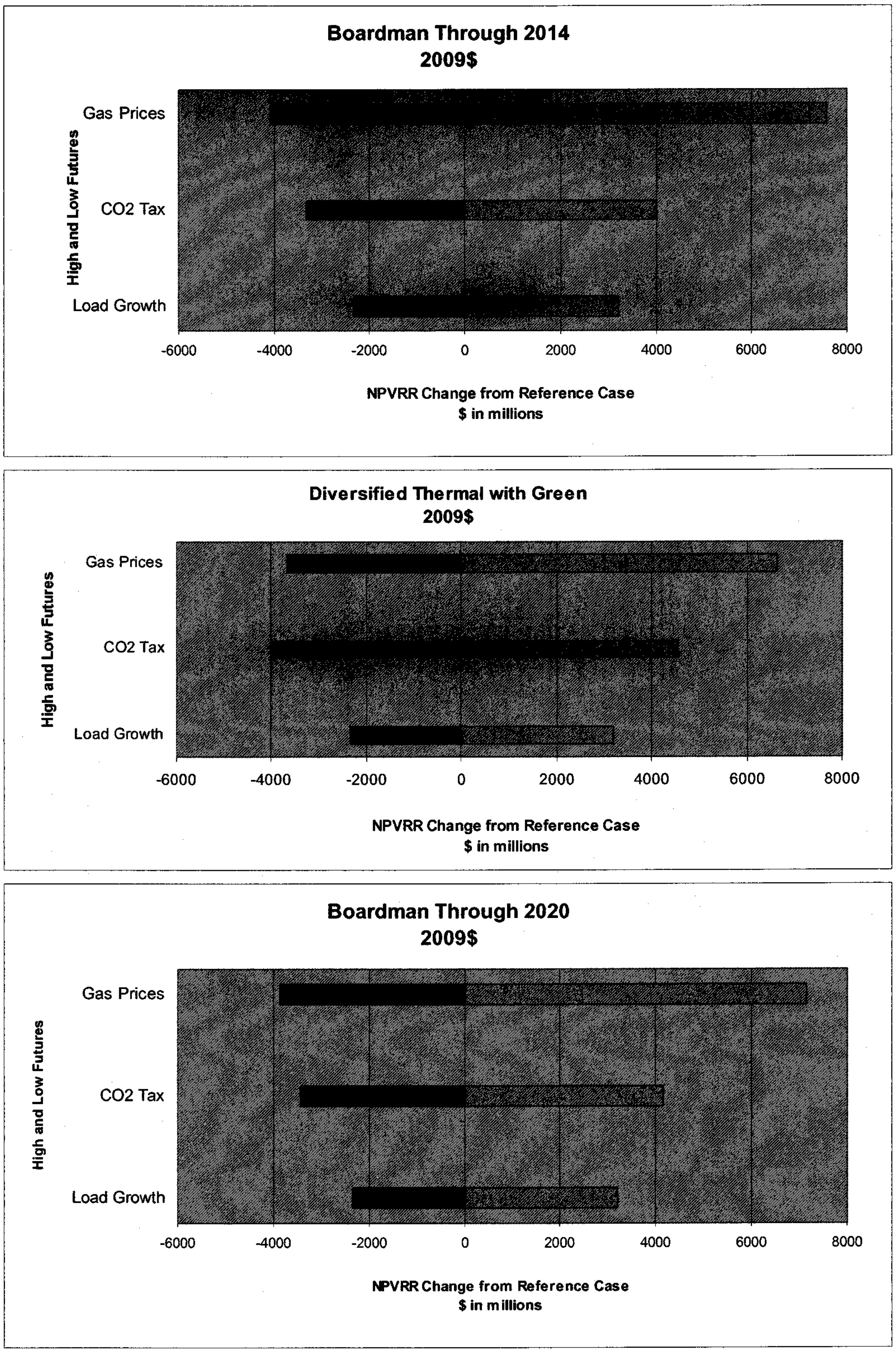
"Boardman Through 2014" and "Boardman Through 2020" are more exposed to gas price risk than "Diversified Thermal with Green", because a gas-fuelled CCCT is the assumed replacement technology for Boardman in these portfolios. However, of these two, "Boardman Through 2020" has less gas price risk than "Boardman Through 2014".

"Diversified Thermal with Green" is more exposed to CO_2 risk. This reflects the higher CO_2 output profile of a coal plant compared to a CCCT. Exposures to load growth are essentially the same for all three portfolios.

Another insight from these graphs is the apparent asymmetry between upside and downside exposure to gas price risk, while CO_2 cost risk and load growth have fairly balanced risk profiles. This reflects the asymmetry of the high and low natural gas prices as compared to the reference case price, since gas prices can rise higher than they can fall.

Of the three major cost drivers, natural gas price risk emerges as the greatest driver of the portfolio NPVRR and as a result, the single largest risk factor. CO_2 compliance cost is second and load growth is third. Load growth risk magnitude is equivalent for all three portfolios.

Figure 12A-10: Boardman Portfolios' Sensitivities



12A.6 Assessing Boardman Analytical Results

Our portfolio analysis, using both scenario and stochastic approaches, provides a comprehensive look at Boardman's value and risks. Overall, "Boardman through 2020" performs better than the other Boardman alternatives, when considering the combined portfolio scoring measures – see Table 12A-2 below. The "Boardman through 2020" portfolio clearly outperforms the other early closure cases with respect to both cost and price risk. In general, the "Boardman through 2020" portfolio strikes a good balance between the key risk drivers of natural gas and CO_2 prices, while maintaining system reliability at a relatively low cost. Diversified Thermal with Green also provides a good balance between cost and risk, performing relatively well on expected cost as well most of the risk, durability and diversity measures. Given these results, "Boardman through 2020" is our preferred portfolio, while "Diversified Thermal with Green" represents our next best option when compared to other Boardman alternatives.

Table 12A-2: Boardman Portfolio Analysis Scoring Grid

	1. Portfolio Evaluation Scoring: Raw Performance Metrics	Screening		Deterministic				Stochastic					Reliability & Diversity		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Frontier Zone?	Meets Operating Reserve Req?	Cost: Expected Cost Reference Case	Prob. of Poor Perf.	Prob. of Good Perf.	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variation	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
	Units	Y or N	Y or N	$ NPV	%	%	%	$ NPV Million	$ NPV Million	$ NPV Million	$ NPV Million	Trillion	MWa	Points	Points
9	Diversified Thermal with Green	Y	Y	$ 28,674	5%	24%	19%	$ 34,910	$ 6,236	$ 36,116	$ 8,171	53	757	2532	2073
10	Boardman through 2014	Y	Y	$ 28,593	5%	67%	62%	$ 35,126	$ 6,533	$ 38,112	$ 9,689	63	737	3075	2172
12	Boardman through 2011	Y	Y	$ 28,777	10%	10%	0%	$ 35,247	$ 6,470	$ 38,142	$ 9,551	62	714	3075	2245
13	Boardman through 2020	Y	Y	$ 28,396	0%	81%	81%	$ 34,770	$ 6,374	$ 36,999	$ 8,987	61	749	3075	2079
16	Boardman through 2017	Y	Y	$ 28,780	10%	0%	-10%	$ 35,257	$ 6,477	$ 37,877	$ 9,358	61	736	3076	2111

Performance Range for Scoring Normalization:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Best Performing Portfolio(s)			$ 27,211			86%	$ 33,993	$ 4,632	$ 34,481	$ 6,191	$ 37	$ 714	$ 2,036	$ 1,824
Best Basis			Min			Max	Min	Min	Min	Min	Min	Min	Min	Min
Worst Performing Portfolio(s)			$ 32,735			-100%	$ 38,635	$ 8,943	$ 38,142	$ 9,689	$ 78	$ 1,050	$ 3,137	$ 2,316
Spread Best to Worst			$ 5,524			186%	$ 4,641	$ 4,311	$ 3,661	$ 3,498	$ 42	$ 336	$ 1,101	$ 492
% Difference			20.3%				13.7%	93.1%	10.6%	56.5%	113.9%	47.1%	54.1%	27.0%

	2. Portfolio Evaluation Scoring: Normalized Scores (0 to 100)	Screening		Deterministic				Stochastic			Reliability & Diversity		
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Frontier Zone?	Meets Operating Reserve Req?	Cost: Expected Cost	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variation	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
9	Diversified Thermal with Green	Y	Y	73.5	64.1	80.3	62.8	55.3	43.4	61.2	87.3	54.9	49.3
10	Boardman through 2014	Y	Y	75.0	87.2	75.6	55.9	0.8	0.0	37.6	93.0	5.6	29.3
12	Boardman through 2011	Y	Y	71.7	53.8	73.0	57.4	0.0	4.0	40.0	100.0	5.6	14.3
13	Boardman through 2020	Y	Y	78.6	97.4	83.3	59.6	31.2	20.1	42.9	89.6	5.6	48.0
16	Boardman through 2017	Y	Y	71.6	48.7	72.8	57.2	7.2	9.5	41.0	93.4	5.5	41.7

	3. Portfolio Evaluation Scoring: Total Weighted Scores	Screening		Deterministic				Stochastic			Reliability & Diversity					
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	[illegible]	[illegible]
	Scoring Consideration	Within Efficient Frontier Zone?	Meets Operating Reserve Req?	Cost: Expected Cost	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variation	Reliability: TailVar Unserved Energy 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI	Weigted Combined Score (0 to 100)	Performance vs. Best [illegible]	[illegible]
	Weight			50%	10%	5%	5%	3.3%	3.3%	3.3%	15%	2.5%	2.5%			
9	Diversified Thermal with Green	Y	Y	36.8	6.4	4.0	3.1	1.8	1.4	2.0	13.1	1.4	1.2	71.4	96%	[illegible]
10	Boardman through 2014	Y	Y	37.5	8.7	3.8	2.8	0.0	0.0	1.3	14.0	0.1	0.7	68.9	93%	[illegible]
12	Boardman through 2011	Y	Y	35.8	5.4	3.6	2.9	0.0	0.1	1.3	15.0	0.1	0.4	64.7	87%	[illegible]
13	Boardman through 2020	Y	Y	39.3	9.7	4.2	3.0	1.0	0.7	1.4	13.4	0.1	1.2	74.1	100%	[illegible]
16	Boardman through 2017	Y	Y	35.8	4.9	3.6	2.9	0.2	0.3	1.4	14.0	0.1	1.0	64.3	87%	[illegible]

Other Considerations

The "Boardman through 2020" portfolio has other compelling advantages not captured in our IRP scoring compared to the "Boardman through 2014" and other Boardman alternatives examined here:

- It preserves the near-term economic value of the plant thereby saving customers around $600 million dollars over the next decade compared to the earlier closure alternatives.
- It avoids the acceleration of additional costs and the corresponding customer rate pressure during a time when other IRP resource actions are also being implemented.
- It allows time for other greener technologies beyond wind to develop and economically mature, potentially allowing for a greater range of replacement options by 2020 than are available today for implementation by 2014.
- It provides a hedge against compliance costs of any future greenhouse gas legislation when compared to plans that operate Boardman through 2040
- It allows for an orderly transition for Boardman plant employees and the local community.

Boardman Recommendation

PGE's preferred Action Plan is based on the "Boardman through 2020" portfolio. It includes the following investments in emissions controls:

- NOx Controls: install the LNB/MOFA control system which, as proposed, is estimated to reduce NOx by 4,000 tons per year, for nearly a 50% reduction compared to current emission levels. These controls will be installed by July 2011 to meet the 0.28 lb/MMBtu (30-day rolling average) and 0.23 lb/MMBtu (12-month rolling average) emissions limit. The estimated overnight capital cost is $33 million (100% of Boardman plant). Engineering Procurement and Construction (EPC) work will start in early 2010 to support the July 2011 schedule.
- Mercury Controls: install the mercury (Hg) control system by 2012 for an estimated overnight capital cost of approximately $8 million (100% of Boardman plant).

- SO_2 Reductions: procure lower sulfur coal which will reduce SO_2 emissions 20% below current permit levels by the end of 2011 and 50% below current permit levels in 2014. (Incremental costs to procure new, lower sulfur coal supply have not been factored into our portfolio analysis, but any additional costs are not expected to have a material impact on the comparative economics of the candidate portfolios.)

Table 12A-3 below provides the dates by which equipment must be installed in order for PGE to meet its compliance obligations. An all-inclusive engineering, procurement and construction (EPC) approach is preferred for the LNB/OFA controls.

Table 12A-3: Boardman Engineering Procurement and Construction Schedule

	Controls	**EQC Emission Compliance Date**	**EPC Contract Date**
1.	LNB/OFA	July 2011	March 2010
2.	mercury	July 2012	Q2-Q3 2010

Table 12A-4 below summarizes the capital costs that are modeled in our IRP analysis and are associated with each of PGE's recommended emissions controls. Capital costs in this table are 100% share of the Boardman plant. Installation of the new control systems is expected to take place during our normally scheduled spring maintenance outages.

Table 12A-4: Proposed Boardman Emissions Controls Capital Costs, Nominal $

	LNB/OFA	Hg	Total
2007	75	25	100
2008	468	156	624
2009	1,554	77	1,632
2010	16,628	233	16,861
2011	14,123	4,819	18,943
2012	-	2,345	2,345
2013	-	-	-
2014	-	-	-
2015	-	-	-
2016	-	-	-
2017	-	-	-
	32,849	7,655	40,504
AFDC	3,636	912	4,548
Property Tax	386	108	494
Total	36,872	8,675	45,546

With all proposed BART II controls in place in 2014, variable and fixed non-fuel O&M will not change materially.

This analysis is based on PGE's cost of capital. Tax-favored pollution control bond financing, if available, could improve the economics. Our modeling assumes no extension of the Oregon Pollution Control Facilities Tax Credit program, which currently does not benefit controls that were placed in service after December 31, 2007.

Boardman Alternate Recommendation

As discussed in detail in Chapter 13A, if PGE is not able to move forward with its preferred Action Plan by March 31, 2011, then it requests that the Commission acknowledge that it is prudent to move forward with an alternate Action Plan based on the "Diversified Thermal with Green" portfolio (with or without lease). The costs for the emissions control equipment associated with the alternate Action Plan are described in our November, 2009 IRP filing, which for convenience we replicate below.

Phase 1

- <u>NOx Controls</u>: install the LNB/MOFA control system which, as proposed, is estimated to reduce NOx by 4,000 tons per year, for a 46% reduction compared to current emission levels. These controls will be installed by July 2011 to meet the 0.28 lb/MMBtu (30-day rolling average) and 0.23 lb/MMBtu (12-month rolling average) emissions limit. The estimated overnight capital cost is $33 million (100% of Boardman plant). Engineering Procurement and Construction (EPC) work will start in early 2010 to support the July 2011 schedule. We anticipate that it will not be necessary to request a compliance extension, thereby changing the dual limits to a single 0.23 lb/MMBtu (30-day rolling average) emissions limit.

- Mercury Controls: install the mercury (Hg) control system by 2012 for an estimated overnight capital cost of $7.7 million (100% of Boardman plant).

- SO_2 Controls: install scrubbers, which will cut SO_2 emissions by 12,000 tons per year for an 80% reduction compared to current emission levels. These controls will be installed by July 2014 to meet the 0.12 lb/MMBtu 30-day average emissions limit.

- Particulate Matter Controls: install a pulse jet fabric filter as part of the scrubber installation to supplement the existing electrostatic precipitator. This installation will cut particulate matter emissions by 122 tons per year for a 29% reduction from current levels. These controls will be installed by July 2014 to meet the 0.012 lb/MMBtu emissions limit. The particulate matter controls, together with the scrubbers, are estimated to have overnight capital cost of $289.9 million (100% Boardman plant).

Phase 2

- NOx Controls: install Selective Catalytic Reduction (SCR), which will cut NOx emissions by an additional 4,000 tons per year for an additional 38% reduction, beyond the Phase I upgrades. These controls will be installed by July 2017 to meet a 0.070 lb/MMBtu emissions limit for an estimated overnight capital cost of $180 million (100% Boardman plant).

Table 12A-5 below provides the dates by which equipment must be installed in order for PGE to meet its compliance obligations. An all inclusive engineering, procurement and construction (EPC) approach is preferred, except for the Hg controls.

Table 12A-5: Boardman Engineering Procurement and Construction Schedule

	Controls	EQC Emission Compliance Date	EPC Contract Date
1.	LNB/OFA	July 2011	March 2010
2.	Mercury	July 2012	Q2-2011
3.	FGD	July 2014	Q1-2011
4.	SCR	July 2017	Q1-2014

Table 12A-6 below summarizes the capital costs associated with each of the emissions controls according to the alternate Action Plan recommendation; capital costs in this table are for 100% of the Boardman plant output. Installation of the new systems is expected to take place during our normally scheduled spring maintenance outages.

Table 12A-6: Boardman Emissions Controls Capital Costs, Nominal $

	LNB/OFA	Hg/FGD	SCR	Total
2007	$ 75	$ 100	$ 75	$ 250
2008	$ 468	$ 624	$ 468	$ 1,560
2009	$ 1,554	$ 376	$ 77	$ 2,007
2010	$ 16,628	$ 3,785	$ 116	$ 20,529
2011	$ 14,123	$ 85,862	$ 94	$ 100,079
2012	$ -	$ 127,146	$ 116	$ 127,262
2013	$ -	$ 58,570	$ 684	$ 59,254
2014	$ -	$ 21,042	$ 38,789	$ 59,831
2015	$ -	$ -	$ 80,564	$ 80,564
2016	$ -	$ -	$ 43,720	$ 43,720
2017	$ -	$ -	$ 15,350	$ 15,350
Overnight Capital	**$ 32,848**	**$ 297,505**	**$ 180,053**	**$ 510,406**
AFDC	$ 3,636	$ 73,627	$ 42,352	$ 119,615
Property Tax	$ 386	$ 9,913	$ 5,727	$ 16,026
Total	**$ 36,870**	**$ 381,045**	**$ 228,132**	**$ 646,047**

With all controls in place in 2017, total fixed and variable O&M for PGE's 65% share of Boardman is projected to increase by approximately $8.1 million in 2009$. About two-thirds of this amount is variable O&M. At the same time, the net plant heat rate is projected to increase by about 2% and plant output is projected to decrease by the same percentage. The ongoing impacts to the dispatch cost due solely to emissions controls (the variable O&M and change in heat rate) are fairly modest. In 2017, when all controls are in place, the non-fuel dispatch cost is expected to increase by approximately $3 per MWh in 2009 $ exclusive of CO_2 costs.

As discussed in further detail in Chapter 13A, PGE recommends acknowledgement of our preferred Action Plan based on the Boardman through 2020 portfolio. In the event that the contingencies associated with the preferred Action Plan (as outlined in Chapter 13A) can not be resolved, we recommend proceeding with our alternate Action Plan based on the Diversified Thermal with Green portfolio.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-18

IDAHO POWER COMPANY

ATTACHMENT NO. 3

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 48

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2009 Integrated Resource Plan.	ORDER

DISPOSITION: PLAN ACKNOWLEDGED WITH REQUIREMENTS

I. INTRODUCTION

Portland General Electric Company (PGE or the Company) seeks acknowledgment of its 2009 Integrated Resources Plan (IRP) and 2010 Addendum. In this order 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 adopted 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.[1] The remaining twelve guidelines include procedural requirements that provide direction on how to prepare and update the plan, and other provisions that address specific resources such as transmission and conservation.

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[1] Docket UM 1056, Order No. 07-002 (Jan 8, 2007).

B. Effect of Acknowledgement of an IRP on Future Ratemaking Actions

The Commission's role in reviewing an IRP is to determine whether the IRP meets the substantive and procedural guidelines in Order Nos. 89-507 and 07-002. The Commission generally does not address the need for specific resources, but rather determines whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk.[2] Commission acknowledgement of an IRP means only that the Commission finds that the utility's preferred portfolio is reasonable at the time of acknowledgement.[3]

In Order No. 89-507, the Commission described its role in reviewing and acknowledging a utility's least-cost plan:

> The establishment of Least-Cost Planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission.
>
> * * * * *
>
> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan.[4]

This order does not constitute a determination on the ratemaking treatment of any resource acquisitions or other utility expenditures. As a legal matter, the Commission must reserve judgment on all ratemaking issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the ratemaking process. In ratemaking proceedings, in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged plans. A utility is expected to explain actions they take that are inconsistent with Commission-acknowledged plans.

C. Procedural History

PGE filed its 2009 Integrated Resource Plan on November 5, 2009. In that filing, PGE proposed to invest over $500 million to retrofit its Boardman coal-fired plant

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[2] *See* Order No. 07-002 at 25.
[3] *See Id.* at 16.
[4] *See* Order No. 89-507 at 6, 11 (Docket UM 180). The Commission affirmed these principles in Docket UM 1056. *See* Order No. 07-002 at 24.

(Boardman) to meet requirements of the Oregon Environmental Quality Commission's (EQC) Regional Haze Plan and operate the plant until 2040. Following a prehearing conference on December 1, 2009, an administrative law judge issued a procedural schedule that included a presentation to the Commission on January 19, 2010.

On January 14, 2010, PGE 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 retrofit the Boardman plant and operate it until 2040 in a manner that would be acceptable to the EQC and other stakeholders. On January 15, 2010, the Commission stayed all proceedings in this docket.

On April 9, 2010, PGE filed an addendum to its IRP that included a revised operating plan for Boardman. Following the adoption of a new procedural schedule, however, we delayed proceedings to allow PGE, intervenors, and Commission Staff (Staff) the opportunity to consider whether certain EQC and Department of Environmental Quality (DEQ) actions might impact PGE's revised IRP. Staff noted that EQC would soon 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.

A final procedural schedule was subsequently adopted that required PGE to file reply comments analyzing three DEQ-proposed alternatives for Boardman retrofits and operation and responding to earlier filed comments. The procedural schedule gave intervenors the opportunity to respond to PGE's supplemental comments, PGE the opportunity to file reply comments on September 27, 2010, and directed Staff to file recommendations and a proposed order. 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.

In sum, the procedural schedule in this docket included multiple opportunities for the parties to address PGE's IRP. This included three rounds of written comments; three public meetings; two technical workshops (to address Cascade Crossing and Boardman); and public comment hearings in Portland and Boardman, Oregon.

D. Parties and Comments

The following entities intervened in this proceeding: the Northwest and Intermountain Power Producers Coalition; the Citizens' Utility Board of Oregon (CUB); NW Energy Coalition (NWEC); Ecumenical Ministries of Oregon (EMO); Oregon Environmental Council, PacifiCorp, dba Pacific Power; Iberdrola Renewables, Inc.; Oregon Department of Energy (ODOE); the Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, and the Northwest Environmental Defense Center; Renewable Northwest Project (RNP); Physicians for Social Responsibility; Northwest Pipeline GP; the City of

Portland; Industrial Customers of Northwest Utilities; Turlock Irrigation District; International Brotherhood of Electrical Workers, Local 125 (IBEW 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 (Salem Chamber); Strategic Economic Development Corporation; Clackamas County Business Alliance; Columbia Corridor Association; Associated Oregon Industries; Westside Economic Alliance; Portland Business Alliance; Association of Oregon Counties; the Wilsonville Chamber of Commerce; SEDCOR, Morrow County; Oregonians for Food and Shelter; Oregon Farm Bureau Federation; 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, Oregon. 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

A. Load Forecast and Resource Need

1. Parties' Positions

The Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, and the Northwest Environmental Defense Center (NEDC) (collectively referred to as the Coalition), as well as NW Energy Coalition (NWEC); Willard Rural Association (WRA); and Ecumenical Ministries of Oregon (EMO) argue that PGE has overstated its reference case load forecasts and, therefore, its future energy and capacity needs. Many of these parties argue that this has a direct bearing on the options for shutdown of Boardman.

The Coalition, NWEC, and EMO all argue that PGE's load forecasts are inconsistent with recent historical load growth in PGE's service territory. The Coalition emphasizes that since 2000 the yearly growth in sales has exceeded PGE's March 2009 projected growth rate of 1.9 percent per year for 2010 through 2030 only once.[5] NWEC points to analysis by WRA that shows PGE's load growth has been essentially flat over the past ten years and questions why the next ten years should be projected to be any different.[6]

The Coalition urges the Commission to consider the differences between the Company's March 2009 load forecasts used in the IRP and its more recent December 2009 load forecasts.[7] The Coalition provides the year-by-year reductions in peak load and annual average energy and argues that the forecast reductions are significant and material. For

[5] Coalition's Sept 1, 2010 Comments at 17-18 (Schlissel Technical Consulting, Inc. (Schlissel))
[6] NWEC's May 14, 2010 Comments at 5.
[7] Coalition's Sept 1, 2010 Comments at 16-17 (Schlissel).

example, the December 2009 forecasts show reductions of 157 megawatts (MW) in peak load and 152 average MW (MWa) in annual energy during 2015.

NWEC, the Coalition, and EMO all argue that PGE's load forecasts are inconsistent with those of independent forecasters. NWEC takes issue with PGE's comparison of its projected load growth of 1.72 percent for the period 2010–2015, assuming a continuation of historic levels of embedded energy efficiency, to the Northwest Power and Conservation Council's (NPCC) Draft Sixth Plan projected load growth for Oregon of 1.96 percent. NWEC argues that the appropriate comparison is to an adjusted load growth forecast for Oregon of 0.47 percent per year. NWEC calculated this adjusted growth rate after subtracting the NPCC's forecast of future energy efficiency from its medium-load forecast.[8]

Staff argues that PGE's reference case forecast is too high because it does not adequately account for the continued effect of the 2007–2009 recession.[9] Staff contends that the NPPC's Final Sixth Plan projected annual load growth of 1.4 percent for 2010–2015 is more reasonable than PGE's projected 1.7 percent. Staff indicates that this level of growth is consistent with PGE's low-case forecasts. Staff also attempts to put this adjustment into the context of PGE's overall resource need. Staff indicates that under PGE's reference case load forecast, with Boardman operating, PGE is short 952 annual 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. Under this low load scenario, the winter and summer capacity deficits are 1,979 MW and 1,788 MW, respectively, in 2016. Staff asserts that these resource gaps under the low load forecasts are still significant and would be challenging to fill if Boardman were shut down in 2016.

PGE responds that its forecasts appropriately incorporate data from both the recent and distant historical past. PGE acknowledges that load growth exceeded the forecasted average rate of 1.9 percent only once since 2000, but adds that that historic annual growth exceeded 1.9 percent during sixteen of the last twenty-eight years.[10] PGE also notes that the differences between its March 2009 and December 2009 load forecasts can be explained in part by different accounting treatment of Senate Bill 838 energy efficiency and by recession-driven reductions in a very limited set of large industrial customer loads. PGE emphasizes that the load reduction of 152 average MW in 2015 needs to be put into the context of PGE's overall forecasted resource need of 873 average MW in 2015.[11]

2. Commission Resolution

We agree that PGE's reference case load forecast for the 2010-2015 period is likely too high because it fails to account for the lingering effect of the 2007-2009 recession. We also agree with PGE and Staff that we must consider this within

[8] NWEC's May 14, 2010 Comments at 5.
[9] Staff's Oct 15, 2010 Comments at 9.
[10] PGE's Sept 28, 2010 Comments at 14.
[11] *Id* at 13.

the context of PGE's overall resource needs. Even under the low-load scenarios, and even if Boardman keeps operating, PGE has significant resource needs. PGE's future resource needs are driven not just by growing demand, but also by the expiration of key power purchase contracts held by the Company.

In an IRP, we require utilities to evaluate alternative resource portfolios across a wide range of potential futures, including those with low, medium, and high demand for electricity. PGE's range of load forecasts appears reasonable. PGE evaluated its resource portfolios across this range of load forecasts. Our finding that PGE's reference case load forecast is likely overstated does not change our decision regarding Boardman and the best resource options for ratepayers, as discussed in the next sections.

We do not agree with NWEC that PGE's projected average annual growth in load is significantly higher than that projected by NPCC. PGE correctly compares its forecasts with embedded energy efficiency to NPCC's "frozen efficiency" forecasts. This "apples-to-apples" comparison is consistent with the IRP objective of measuring resource need prior to the addition of any demand- or supply-side resource actions. More fundamentally, we agree with PGE that this comparison is founded on the faulty premise that the Pacific Northwest is one large homogeneous region in terms of economics and demographics. As PGE points out, for example, its service territory is more urban and has more high-technology customers than the rest of the region. There are many good reasons why load growth rates will differ by area within a state and within the region.

B. Natural Gas Price Forecast Method

1. Parties' Positions

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. The Coalition compares PGE's reference case natural gas prices forecasts to those of the NPCC, Staff, and the U.S. Energy Information Administration (EIA).[12] 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.[13]

Staff agrees also with the Coalition that PGE's reference case natural gas price is slightly overstated. Staff argues that PGE's forecasting methodology is flawed because the Company only relies on a single source, PIRA Energy Group, for its long-term natural gas price forecast. Staff also argues that PGE's short-term price forecast is flawed because it only relies on NYMEX futures prices, and does not include fundamentals based price forecast. Staff recommends that the Commission require PGE to obtain natural gas prices forecast from multiple third party sources.

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[12] Coalition's May 19, 2010 Comments at 4-10 (Schlissel).
[13] Coalition's Sept 1, 2010 Comments at 12 (Schlissel).

In response to Staff's analysis and recommendations, PGE states that it is unaware of any bias in PIRA's forecasts. PGE also notes that it appears that Staff compared the IRP's August 2009 PIRA forecast to the 2010 forecasts of EIA and Wood MacKenzie Research and Consulting. PGE notes that comparing PIRA's 2009 forecast to these 2010 forecasts is misleading because most forecasters reflected a downturn in prices for 2010.[14] With respect to Staff's observations regarding PGE's use of NYMEX future prices for near-term forecasting, PGE maintains that using prices from actual trades reflects the most current and accurate information that is available in the market.[15]

2. *Commission Resolution*

We agree that PGE's reference case natural gas price forecast is likely overstated because of the lingering effect of the 2007-2009 recession and recent developments related to shale gas production. In IRPs, we require utilities to evaluate alternative resource portfolios across a wide range of potential futures, including those with low, medium, and high prices for natural gas. PGE's range of natural gas prices appears reasonable. PGE's natural gas forecasts satisfy IRP Guidelines 1b and 4g.
Our finding that PGE's reference case natural gas prices are likely overstated does not change our decision regarding Boardman. We decline to require PGE to use multiple forecasting sources in future IRPs. We expect PGE to continue to update its natural gas price forecasts in future IRPs and IRP Updates.

C. Boardman

1. *Parties' Positions*

PGE requests that the Commission acknowledge continued coal-fired operations at Boardman as outlined in the Company's BART III proposal submitted to the DEQ on July 30, 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.

As part of its BART III proposal, PGE proposes the following compliance actions to meet Oregon Regional Haze Plan and Oregon Utility Mercury Rule standards:

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;

[14] PGE's Nov 1, 2010 Comments at 13-14.
[15] *Id.*

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.[16]

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.

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 Boardman 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 1 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.[17]

PGE contends that its BART III proposal is superior to these alternatives, and observes that among the early closure options, those that keep Boardman operating 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 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.[18]

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[16] PGE's Aug 10, 2010 Comments at 8-9.
[17] *Id.* at 10-13.
[18] *Id.* at 16.

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 Boardman 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.[19]

PGE argues that the backstop proposal 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 shutdown of Boardman in 2014 as a result of failure to install the dry scrubbers by the BART I deadline.[20] 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.

In its comments on Staff's proposed draft order, PGE states that it asked DEQ to reopen the record in the ongoing DEQ rulemaking proceeding to allow PGE to make a refinement to the BART III plan. PGE noted that CUB, RNP, Angus Duncan,[21] Oregon Environmental Council (OEC), and NWEC support the refined BART III plan. PGE also informed the Commission that PGE has committed to work with stakeholders in the Company's next IRP to evaluate and consider carbon-reduction options for replacement power.[22]

The following parties submitted opening comments that largely support PGE's BART III proposal without qualification: Morrow County, Portland Business Alliance, Oregon Forest Industries Council, Associated Oregon Industries (AOI), Oregon Cattlemen's Association, the Community Action Partnership of Oregon, Strategic Economic Development Corporation, Association of Oregon Counties, Salem Area Chamber of Commerce (Salem Chamber), Wilsonville Chamber of Commerce, Clackamas County Business Association, Columbia Corridor Association, Oregon Farm Bureau, and Oregonians for Food and Shelter. In their reply comments, AOI, Salem Chamber, West Side Economic Alliance, Oregon Forest Industries Council, Association of Oregon Counties, Columbia Corridor Association, and Morrow County strongly suggest the Commission acknowledge PGE's 2040 option as a backstop alternative.

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.

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[19] *Id.* at 15.

[20] *Id.* at 5; IRP Addendum at 124 (April 9, 2010).

[21] Angus Duncan, is an interested person in this docket, is the President and CEO of the Bonneville Environmental Foundation.

[22] PGE's Oct 29, 2010 Comments at 3.

The Physicians for Social Responsibility implored the Commission to consider the serious health concerns and costs associated with continued operation of Boardman beyond 2014.

Other parties submitted comments that challenge PGE's analysis of the Boardman compliance options and contained alternative recommendations for the Commission. We summarize these parties' positions below, as well as some reply comments.

a. The Coalition

The Coalition characterizes PGE's proposed compliance actions as a plan to transition off coal in 2020–or never.[23] 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.[24]

The Coalition further argues that PGE uses unreasonably high natural gas prices in its IRP modeling and biases the results in favor of continued operation of Boardman and against early shutdown scenarios.[25] 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 believes that PGE has overstated its energy and capacity needs.[26] Again, emphasizing the importance of current information, the Coalition argues that PGE should 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.[27]

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[23] Coalition's Sept 1, 2010 Comments at 1-2.
[24] *Id.* at 2-6 (Schlissel).
[25] *Id.* at 7-16.
[26] *Id.* at 16-18.
[27] *Id.* at 18.

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 costs and benefits of replacing some or all of Boardman's output with a mid-term power purchase agreement (PPA).[28] 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.[29]

b. The Joint Parties

CUB, RNP, NWEC, OEC, Angus Duncan, EMO, Sierra Club, and NEDC, (collectively referred to as the Joint Parties) view the proposal to install BART I emissions controls to allow the continued operation of Boardman through 2040 as the most objectionable option before this Commission. They request the Commission 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.[30]

The Joint Parties support closing Boardman 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 regional stakeholders to agree on a comprehensive plan to achieve the responsible closure of Boardman.

The Joint Parties argue that the replacement of Boardman should be significantly cleaner and more flexible resource than replacement with only a base load natural gas plant.[31] The Joint Parties are confident that PGE could replace Boardman in the 2015/2016 timeframe with a diverse mix of resources. The Joint Parties concede the risk, however, that early closure would likely result in replacing the plant 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.

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[28] *Id.* at 19.
[29] *Id.* at 20-21.
[30] Joint Parties' Sept 1, 2010 Comments at 1.
[31] *Id.* at 2.

c. *The NW Energy Coalition*

The NW Energy Coalition (NWEC) joins the Joint Parties in recommending shutdown of Boardman no later than 2020. Like the Joint Parties, NWEC prefers an agreement between PGE, DEQ, and regional stakeholders on a mutually 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.[32]

NWEC opines that not enough effort has been put into developing a resource strategy to replace Boardman.[33] NWEC urges the Commission to consider the state's carbon reduction goals and in the next IRP cycle to begin work on a comprehensive plan to achieve significant reductions in emissions. NWEC repeatedly argues 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.[34] 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 proposal 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 tie-breaking criteria, such as near-term rate impacts, inadequate time to develop replacement resources, and insufficient transition time for its employees and the Boardman community.

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.[35] NWEC has repeatedly argued that the load forecast used by PGE in its IRP modeling is higher than the 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.

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[32] NWEC's Sept 1, 2010 Comments at 1.
[33] *Id.* at 1-2.
[34] *Id.* at 2-6.
[35] *Id.* at 4.

NWEC argues that reliance on the market can provide the space needed in time to acquire a clean mix of replacement resources.

d. NIPPC

The Northwest and Intermountain Power Producers Coalition (NIPPC) offers no opinion regarding the cessation of coal-fired operations at the Boardman plant.[36] NIPPC emphasizes, however, that the shutdown risks being debated in this proceeding are largely ratepayer risks, and believes that diversifying ownership of generation resources is in the best interest of ratepayers. NIPPC says it is well established that 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.[37]

NIPPC 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 PPAs 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.[38] NIPPC argues that postponement of the evaluation of PPAs to the competitive bidding process makes PGE's IRP noncompliant with this guideline.

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.[39] 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 Proposals (RFP) process.[40] 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

[36] *Id* at 2.
[37] *Id.* at 7.
[38] Order No. 07-002 at 3.
[39] NIPPC's Sept 1, 2010 Comments at 5.
[40] *Id.* at 8-9.

resources located at non-PGE sites, as well as sales of existing assets from independent power producers.

e. Staff

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

Staff primarily focuses its analysis of PGE's portfolio modeling on three metrics: (1) expected cost; (2) the average of the four worst deterministic futures; and (3) 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 PGE's 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 significant.

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, however, that the risk associated with the deliverability and cost of such power is not in the best interest of ratepayers.

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. As previously discussed, Staff believes that PGE's 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. Staff notes, however, that PGE's response to the Commission's Bench Request, which tested a combined low natural gas price and 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.

f. Reply Comments

In its reply comments, CUB agrees with Staff that of the options presented in the IRP, BART III is the best performer from a least cost/least risk basis. Nonetheless, CUB believes that the Commission should not specifically acknowledge BART III in the event the

EQC adopts a rule that is substantially similar to BART III, but with a different off-ramp for the DSI technology. CUB recommends the Commission use the following language:

> *If the EQC adopts the BART III compliance actions or compliance actions that are substantially similar to BART III, then this combination of pollution control investments and commitment to cease operation at Boardman no later than 2020 provides the best combination of expected costs and risks for customers. We acknowledge compliance actions that are substantially similar to BART III for the Boardman plant.*[41] (emphasis in original).

NWEC also recommends that the Commission should broaden the scope of its acknowledgment regarding Boardman to allow PGE to proceed with its proposed refinements to BART III, should the EQC and the EPA allow it.[42]

CUB, NWEC, RNP, Angus Duncan, and the OEC also filed joint comments urging the Commission to issue an acknowledgment order "flexible enough to accommodate the refinements that PGE have worked to make possible." These parties also urge the Commission impose a requirement on PGE that tracks with the commitment PGE has made to certain parties to develop low-carbon portfolios for evaluation in PGE's next IRP.[43]

2. Commission Resolution

There are six Boardman options currently under consideration:

- The BART I option with shutdown targeted for 2040
- The Boardman through 2014 option
- PGE's proposed BART III option with shutdown targeted for 2020
- DEQ Option 1 with shutdown targeted for 2020
- DEQ Option 2 with shutdown targeted for 2018; and
- DEQ Option 3 with shutdown targeted for 2015/2016

Of these options, PGE's proposed BART III option offers the best combination of cost and risk for ratepayers. We consider PGE's BART III to be the superior option because (1) it is a low-cost option for ratepayers; (2) it mitigates the risk of future carbon regulation by closing the plant at the end of 2020; (3) it mitigates the risk of acquiring replacement resources by providing the time needed to evaluate and implement a reasonable replacement strategy; and(4) it provides the flexibility needed to test the effectiveness of DSI technology and to adapt the plant's operation to control both SO_2 and particulate matter (PM) emissions prior to the plant's closure.

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[41] CUB's Oct 29, 2010 Comments at 4.
[42] NWEC's Oct 29, 2010 Comments at 2.
[43] Group Comments at 2 (Oct 29, 2010).

The BART I option, which requires a $510 million investment in pollution control equipment in order to operate the plant through 2040, is too costly and too risky. The risk of future carbon regulation, whether it takes the form of cap-and-trade regulation, carbon taxation, or the mandated closure of specific coal plants, makes this an inferior option for ratepayers. Under a worst-case scenario, PGE's ratepayers could potentially pay the cost of replacing Boardman with low carbon emission resources while continuing to pay for pollution control equipment at a plant that no longer operates.

DEQ Option 3, which calls for shutdown of the Boardman plant in late 2015 or early 2016, does not allow enough time for PGE and interested parties to develop and implement a reasonable resource replacement strategy. PGE has argued that any replacement for Boardman needs to be a base load resource and has modeled replacement with a natural gas CCCT. The Joint Parties and others have indicated a strong preference for replacing Boardman with a mix of renewable resources. The choice of the best replacement resources is a complex decision that should be considered in PGE's IRP process. Closing Boardman in late 2015 or early 2016 does not allow enough time to fully consider and develop alternative replacement options and could result in ratepayers bearing higher costs in the long-run. The same logic and conclusion applies to the Boardman through 2014 option.

DEQ Option 1, which requires a $343 million investment in pollution control equipment and closes the Boardman plant in 2020, is simply too costly for ratepayers. In PGE's IRP modeling, this option and the BART I option are consistently the highest cost options over a wide range of potential futures, including both PGE's reference case scenario and our Bench Request scenario.

DEQ Option 2 lacks the flexibility needed to test the effectiveness of DSI technology and to adapt the plant's operation to control both SO_2 and PM emissions prior to shutdown in 2018. This lack of flexibility makes operating the plant to 2018 a more risky endeavor. If DSI technology is incapable of controlling SO_2 emissions without simultaneously violating PM emission standards, then PGE and its ratepayers would be confronted with the choice of making an expensive investment in additional pollution control equipment or closing the plant prior to the 2018 target. The increased risk of shutdown prior to 2018 raises the issue of having enough time fully develop and implement a reasonable resource replacement strategy. For these reasons, we find PGE's BART III option to be superior to DEQ Option 2.

As noted, PGE requested that DEQ re-open its BART rulemaking to consider a refinement to PGE's BART III option. The refinement consists of a lower SO_2 emissions requirement beginning July 2018 and a request to repeal the existing BART I option if PGE's BART III option is ultimately approved by the EQC and the EPA. With this refinement, and a PGE commitment to work with regional stakeholders to develop low-carbon resource portfolios for consideration in its next IRP, CUB, NWEC, OEC, and RNP now support Boardman shutdown no later than 2020.

PGE proposes to reach the lower SO_2 emissions standard with increased use of DSI beginning in July 2018. This change increases the total expected net present value cost of the BART III option by $10 million. This change in cost is not significant enough to alter our finding that BART III is the best option for ratepayers. We acknowledge both PGE's original and refined BART III options.

We decline, however, to adopt CUB's recommendation to acknowledge other compliance actions that are "substantially similar" to BART III for the Boardman plant. Although we share CUB's preference to not be involved in an IRP Update proceeding that is comparing small differences in BART compliance actions, the evaluation of differences in resource portfolios is complex and the determination that two options are equivalent is not amenable to allowing parties to interpret the phrase "substantially similar."

We also decline to acknowledge BART I as a backstop option. 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. If the EQC denies the Company's BART III proposal, then PGE has the ability to present its next preferred option, and ask for Commission acknowledgment, in an IRP Update. There is no limit on the frequency of IRP Updates and, if needed PGE can expeditiously file a Boardman-Only Update and also file a general IRP Update a year from now.

We also decline to not acknowledge BART I. We will wait for the EQC to make its decision on BART III before we consider any backstop option. Our decisions do not address the question of the prudence of pursuing the BART I compliance actions; they simply mean that we refuse to prejudge the EQC's actions.

Finally, our acknowledgement of PGE's BART III, conditional on EQC approval, does signal our intention to address the replacement strategy for Boardman in PGE's next IRP.

D. Cascade Crossing

The Cascade Crossing Transmission Project (Cascade Crossing) is a proposed 500 kV transmission line connecting PGE's Boardman and Coyote Springs plants to the southern portion of the Company's service territory. The proposed project would begin at the 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, as well as improvements to two existing substations.[44]

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 for

[44] IRP at 187.

existing generators as an alternate to service furnished by the Bonneville Power Administration (BPA); and (5) improve reliability by providing additional transmission and reducing load on transfer paths parallel to Cascade Crossing, thus reducing the severity of currently limiting contingencies.[45]

PGE conducted a benefit-cost analysis of the Cascade Crossing transmission project to determine whether it should include Cascade Crossing its IRP Action Plan and continue to invest in the project. The choice analyzed was whether it is preferable for PGE's ratepayers to continue to purchase transmission capacity from the BPA or to obtain transmission capacity by building Cascade Crossing. PGE's analysis consisted of five case studies with different assumptions regarding third party equity participation in Cascade Crossing and different assumptions regarding the growth of BPA's transmission rates after 2025.

PGE analyzed both a single-circuit and double-circuit configuration of the Cascade Crossing. For the single-circuit configuration, PGE estimated total project costs to be $613 million and assumed a path rating of 1,500 MW of transfer capability. For the double-circuit configuration, PGE estimated total costs of $823 million and assumed a transfer capability of 2,200 MW. Under Case 3, its mid-point case study, PGE further assumed that it would partner with a third party to share the costs of the 17-mile segment of transmission line from Coyote Springs to Boardman and for the expansion of the Coyote Springs' substation.

PGE estimated the cost of continued service from BPA by assuming that BPA's current transmission rates experience a one-time increase of 10 percent in 2015 and grow at an average nominal rate of 4 percent from 2011 to 2025. Under its mid-point case study, PGE further assumed that BPA transmission rates grow at a rate of 3.2 percent from 2025 to 2082. In all five of the case studies, PGE included approximately $65.5 million for new transmission substations and radial lines needed to connect PGE's planned resources to the BPA transmission system.

PGE, through its case studies, considered higher and lower levels of equity participation and higher and lower growth of BPA's transmission rates after 2025. For example, in Case 1, PGE assumed no equity participation in the 17-mile line segment from Coyote Springs to Boardman and a growth rate of 2.5 percent in BPA's transmission rates after 2025. In Case 5, PGE assumed an additional third party equity share equivalent to 209 MW of transfer capability under the single-circuit configuration (or 300 MW under the double-circuit configuration) and a growth rate of 3.5 percent in BPA's transmission rates after 2025.

PGE seeks acknowledgment to build Cascade Crossing as a double-circuit 500 kV and alternatively, as a single-circuit 500 kV facility. 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 path rating, the level of equity participation from third parties, transmission service requests

[45] *Id.* at 189-190.

received by PGE, and updated information regarding PGE's generation facilities that would utilize the project.

1. 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.[46]

CUB does not recommend against acknowledging Cascade Crossing , but raises numerous questions and concerns. These include: (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; and (4) Should new transmission be a top priority for PGE?

Willard Rural Association (WRA) recommends that the Commission not acknowledge Cascade Crossing. WRA asserts that PGE made many forecasting errors, including: (1) overstating its load forecast; (2) understating the amount of transmission BPA will have in the future; (3) overstating the cost of BPA transmission; (4) underestimating the cost to acquire right of way for Cascade Crossing; and (5) understating 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 IRP 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 analyses (some done in response to a Staff data request) support PGE's proposal to build Cascade Crossing, as opposed to acquiring transmission in another manner.

2. Commission Resolution

The primary benefit of Cascade Crossing is that PGE can avoid future increases in BPA's transmission rates. Cascade Crossing can achieve these savings by connecting PGE's existing Boardman and Coyote Springs plants, and any new generation located in eastern Oregon, directly to PGE's load. PGE's analysis shows that the single-circuit configuration of Cascade Crossing provides net benefits to ratepayer under the mid-

[46] RNP's Sept 1, 2010 Comments at 3.

point and high equity participation cases. The double-circuit configuration only shows net benefits under the high equity participation cases.

PGE did not attempt to quantify all of the potential benefits of Cascade Crossing in its benefit-cost analysis. For example, in all cases PGE assumed zero revenues from transmission sales or use in the west-to-east direction. PGE also did not estimate the potential reliability benefits or the savings in energy losses that would accrue to PGE ratepayers from building Cascade Crossing.

Further, under both the single- and double-circuit configurations, Cascade Crossing would provide other load serving entities the opportunity to access new renewable resources located east of the Cascade Mountains. Pacific Power recently signed a Memorandum of Understanding with PGE to explore obtaining an equity share in the line equivalent to 600 MW of bi-directional transfer capability.

PGE's benefit-cost analysis is sufficiently robust, and shows sufficient net benefits under certain scenarios, to allow us to acknowledge Cascade Crossing at this time. However, when developing an IRP, we always expect utilities to update their assessments of previously acknowledged projects that are still in the planning or development stages. We make this updating requirement explicit for the Cascade Crossing project because of the current uncertainty regarding equity participation and other key factors. We expect PGE to provide a thorough update of the Cascade Crossing benefit-cost analysis in its next IRP, with the understanding that Commission acknowledgment of the Company's next IRP will depend on the outcome of that updated analysis. Therefore, we acknowledge Cascade Crossing with the following requirement:

> PGE shall include an updated benefit-cost analysis of the Cascade Crossing transmission project in its next IRP. For the updated analysis, PGE shall update its assumptions about project configuration, capital cost, path rating, wheeling revenues, and equity participation and conduct sensitivity analyses that address any uncertainty about capital cost, path rating, levels of equity participation, and levels of wheeling revenues.

Finally, we reiterate that, at the time of ratemaking, each utility is required to show that its investment was a prudent decision. At that time, the utility will be expected to address any significant changes in construction cost, path rating, equity partnership, or third-party subscription and how these changes influenced the Company's decision to continue with the project.

E. Demand Response

1. Parties' Positions

Staff contends that PGE did not comply with IRP Guideline 7 regarding demand response (DR) because the Company failed to evaluate DR "on par" with other options for meeting energy, capacity, and transmission needs. Staff notes that PGE included 60 MW of firm DR in its portfolios in 2012 through 2016 (50 MW from an RFP and 10 MW from a curtailment tariff option for large industrial customers) but that the Company did not explain why those were the only DR resources projected in that time period. Staff recommends that the Commission direct PGE to meet Guideline 7 and provide certain information on projected amounts and costs of DR in its next IRP Update.[47]

CUB notes that PGE has not made much progress towards acquiring significant DR since the Commission approved the company's Advanced Metering Infrastructure (AMI) proposal in 2008. CUB agrees with Staff that PGE did not adequately analyze DR in the IRP and recommends that Commission require the company to report in the next IRP Update what steps it will be taking to evaluate DR programs in the Company's next full IRP.[48]

In response, PGE contends that it did comply with the guideline, pointing out in particular that it evaluated DR on par with other resource options by assessing and selecting DR using a benefit/cost ratio based on an alternative capacity resource (a simple cycle combustion turbine or SCCT).[49]

2. *Commission Resolution*

We share the concerns expressed by Staff and CUB. PGE evaluated DR against an SCCT but did not provide DR cost information in the IRP. The Company included 10 MW from a critical peak pricing (CPP) program as a capacity resource in its last (2007) IRP but did not do so in its 2009 IRP, without really explaining the change (other than to say now that it primarily assumes acquisition of firm DR resources). PGE has not made the progress we expected on acquisition of DR, e.g., it has delayed its CPP pilot for a year, and its RFP for direct load control resources was unsuccessful.

We believe that DR can be a significant resource but realize that there is still much to learn about the potential for and reliability of different types of DR (mainly through pilot programs by PGE and other electric utilities). We adopt a combination of the proposals made by Staff and CUB and will require PGE to provide information and show the steps it is taking, and intends to take, to assess and acquire DR. Also, we agree with the timing of these requirements recommended by CUB and Staff and direct PGE to comply with the following directives at the time of its IRP update:

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47 Staff's Oct 15, 2010 Comments at 9-10.

48 CUB's Oct 29, 2010 Comments at 5-7. CUB expressed concern about waiting two years to address DR, apparently because it understood Staff to be proposing a condition for the next IRP. But Staff, like CUB, recommends that PGE report on DR in the next IRP update (which should be filed a year after this order is issued).

49 PGE's Oct 29, 2010 Comments at 7-8.

In its next IRP update, PGE must provide the following:

a. Its estimated cost per MW of capacity savings by demand response (DR) type (i.e., firm vs. non-firm resources), and projected MW acquisitions by DR type for the next 5 years;
b. A discussion of the steps it is and will be taking to evaluate DR in the Company's next IRP, and
c. An updated action plan for assessing (e.g., plans for pilot programs) and acquiring DR for the next 3 years.

F. Energy Efficiency

1. Parties' Positions

Staff concludes that PGE met the IRP guideline for conservation (IRP Guideline 6) with two exceptions. First, Staff states that PGE did not treat conservation voltage reduction (CVR) as a resource. Second, Staff states that PGE did not consider whether to include CVR in the action plan. Staff notes that the Energy Trust of Oregon identified technical potential for 19 MWa of savings from CVR in the Company's service territory.[50]

PGE replies that it views CVR as an operational efficiency, not a long-term resource planning issue. The Commission found that PGE complied with IRP Guideline 6 (except with respect to the planning horizon) in the Company's last IRP, even though its treatment of CVR was the same as in the current IRP. PGE also points out that potential CVR savings are small and would not have a material impact on its resource requirements or action plan.[51]

2. Commission Resolution

We agree with Staff that PGE should consider CVR in its resource planning and adopt the following requirement:

> In its next IRP, PGE should consider conservation voltage reduction (CVR) for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings.

[50] Staff's Oct 15, 2010Comments at 10-11.
[51] PGE's Oct 29, 2010 Comments at 8-9.

G. Renewable Portfolio Standard Requirements

1. Parties' Positions

PGE proposes to acquire 122 MWa of renewable wind generation by the end of 2012 to achieve physical compliance with the Renewable Portfolio Standard (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."[52]

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 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, such as the later availability of 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 overemphasizes 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 recent passage of House Bill 3674. 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.[53]

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.[54]

PGE disagrees with Staff's recommendation that PGE should project future prices and availability for unbundled RECs to assess the potential for acquiring unbundled RECs to meet Oregon's RPS. PGE states, "[w]e believe that, given the lack of liquidity and transparency in the REC markets, it would not be prudent to rely on such projections."[55]

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[52] IRP at 114.
[53] ODOE's May 14, 2010 Comments at 3.
[54] *Id.* at 4.
[55] PGE's Oct 29, 2010, Comments at 10.

2. *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. Accordingly, we adopt the following requirement

In its next IRP Update and in the next planning cycle, PGE must evaluate:

(1) The use of unbundled renewable energy credits (RECs) in its strategy to meet RPS Requirements for the entire planning period; and

(2) Alternatives to physical compliance with renewable portfolio standard (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.

H. Wind Integration Study

1. *Parties' Positions*

RNP recommends that the Commission not acknowledge the wind integration study PGE used to estimate costs to operate and acquire wind generation. RNP asserts that PGE's study includes an unusually high cost of reserves and has not been provided for stakeholders and the Commission to evaluate.[56] 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 agrees 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."[57] 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 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: (1) each

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[56] RNP's Sept 1, 2010 Comments at 1-3.
[57] Docket LC 48, Order No. 08-246 at 10 (May 6, 2008).

utility's costs depend on the unique characteristics of the utility's system; and (2) PGE's wind integration costs is comprised of several components, only one of which is comparable to the within-hour integration tariff.[58]

PGE also disputes RNP's and Staff's criticisms of the wind integration study process. PGE states that it included several stakeholders on its technical review committee to evaluate the Company's study approach, inputs and findings, and conducted a three-hour workshop to present the details of its wind integration study. PGE also notes that, in addition to the input it received from stakeholders the Company hired an independent examiner (IE) in late 2008 to "vet" the study for docket UM 1345, and that the IE concluded the study was a "thorough integration study."[59] Nonetheless, although it believes it has already complied with the requirement to produce a vetted wind integration study, PGE agrees with Staff's recommendation to include in its next IRP Update a wind integration study that has been vetted by regional stakeholders.[60]

2. Commission Resolution

We agree with RNP that it is important that "vetting" by regional stakeholders of a wind integration study include opportunity for regional stakeholders to examine, in detail, the methodology of the study and the results. We also believe that when vetting PGE's wind integration study, stakeholders should have the opportunity to comment on the methodology and make recommendations. Also, it is incumbent on PGE to respond to any such comments and, to the extent it does not adopt recommendations of stakeholders, explain why.

As PGE itself acknowledges, the stakeholder "vetting" consisted of preliminary input from a technical group and a workshop attended by PGE and interested parties. PGE's presentation at the workshop, a hard copy of which PGE attached to its comments, 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 an opportunity for regional stakeholders to evaluate the methodology that PGE actually used and the results obtained from the methodology. Accordingly, we impose the following requirement:

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

I. Risk Metrics

1. Parties' Positions

Staff cautions the Commission about the possible misinterpretation of two risk metrics used by PGE in its 2009 IRP. PGE calculated the "Average of Worst Four Futures

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[58] PGE's Sept 27, 2010 Reply to Intervenor Response Comments at 18.
[59] PGE's Oct 29, 2010Comments at 11.
[60] *Id.*

Less the Reference Case Cost"[61] and "TailVar90 Less the Mean" risk metrics by subtracting a resource portfolio's reference case or mean cost from the average of its "worst-case" or highest-cost outcomes. According to Staff, these calculations can produce counter-intuitive and misleading results. The problem is that the risk metrics may assign a lower risk to a portfolio that has both a higher expected (or reference case) cost and a higher extreme (or worst case) cost. Staff recommends that the Commission rely on PGE's "Average of Worst Four Futures" and "TailVar90" risk metrics that do not subtract the reference case or mean value from the high cost outcomes.

RNP and NWEC also take issue with these two risk metrics. NWEC asserts that these risk metrics are measures of spread or variability, and 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."[62] RNP asserts the metrics do not measure relevant risks.[63] RNP and NWEC also object to PGE's "Year-to-Year Variation" risk measure.[64]

RNP recommends that the Commission require PGE to revise its methodology in future IRPs to appropriately reflect relevant risk factors, dropping duplicative or irrelevant metrics and adding a risk metric proportional to emissions of pollutants, including carbon dioxide.[65] NWEC urges the Commission to direct PGE to improve future IRPs to correct the flaws in its risk analysis and portfolio scoring.[66] NWEC argues that the risk metrics used by PGE assign no weight to the risk of future 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.

In response to NWEC's and RNP's criticisms, PGE asserts that the disputed risk metrics are required by IRP Guideline 1c, which require two measures of risk; one that measures the variability of costs, and one that measures the severity of bad outcomes.[67] According to PGE, the disputed risk metrics satisfy the requirement to have a measure of the variability of costs. The Average of Worst Four Futures and TailVar90 risk measures satisfy the requirement to have a measure of the severity of bad outcomes. Finally, according to PGE, the "Year-to-Year Variance Metric," is necessary because rate stability is important to customers.[68] PGE also rebuts NWEC's assertion its risk metrics assign no weight to future carbon regulation by indicating that the Average of Worst Four Futures and TailVar90 risk metrics do not combine or average high and low CO_2 price futures.

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[61] PGE also refers to this metric as the "Deterministic Portfolio Risk Variability vs. Reference Case." *See* IRP at 249.
[62] NWEC's May 14, 2010 Comments at 13.
[63] RNP's May 20, 2010 Comments at 3.
[64] *Id.*
[65] *Id.*
[66] NWEC's May 14, 2010 Comments at 14.
[67] PGE's Aug 10, 2010 Comments at 46.
[68] *Id.* at 47.

Staff agrees that the Year-to-Year Variance Metric is an important measure of the variability in costs.[69] According to Staff this specific metric obviates the need for the disputed metrics that can be misleading.

2. Commission Resolution

In its 2009 IRP, PGE models the risk and uncertainty associated with load requirements, natural gas prices, electricity prices, plant forced outages, and the cost of compliance with the future regulation of greenhouse gas emissions. Although we share concerns about some of the specific measures used by PGE, PGE's 2009 IRP includes risk metrics that measure both the variability of costs and the severity of bad outcomes for each of the candidate resource portfolios considered in the plan. PGE's risk analysis is robust and satisfies the requirements of IRP Guidelines 1b, 1c, 4i, 4j and 8a.

We decline to adopt NWEC's and RNP's recommendations to require PGE to drop the disputed risk metrics as long as they continue to provide measures that comply with the IRP risk guidelines. We also decline to require PGE to add an additional metric that measures a portfolio's carbon dioxide emissions in its next IRP. PGE provided carbon dioxide emissions analysis, including total emissions in short tons and emissions in short tons per megawatt-hour, for each of the portfolios under consideration in its 2009 IRP. We encourage Staff and other parties to continue to identify risk metrics and results that require careful interpretation and to make resource recommendations based on the metrics and results they find to be most relevant.

J. Reliability

1. Parties' Positions

NWEC comments that PGE's expected unserved energy (EUE) reliability metric measures a resource portfolio's exposure to the wholesale power market and is independent of the portfolio's mix of resources. NWEC notes that, because the EUE metric is a measure of market exposure, it is possible to improve a portfolio's performance simply by adding additional resources. NWEC asserts that the EUE metric should not be used to judge the reliability of PGE's resource portfolios. [70]

Staff also takes issue with PGE's reliability analysis. Staff notes Guideline 11 requires the utility to determine by year for top-performing portfolios (1) the loss of load probability (LOLP), (2) the expected planning reserve margin, and (3) the expected and worst-case unserved energy. Staff asserts that PGE included neither the LOLP metric nor conventional metrics for EUE and Worst-Case Unserved Energy in scoring of its resource portfolios.

Staff notes that instead of calculating a conventional EUE metric, PGE calculated a conditional EUE (CEUE) metric. CEUE is defined as the average amount of

[69] IRP at 267; 285.
[70] NWEC's Sept 1, 2010 Comments at 6-8.

unserved energy that occurs *given* the occurrence of an unserved energy event. Staff echoes NWEC's concern with this metric. Staff notes that a portfolio can get a low CEUE score even if it has a high frequency of unserved energy events. In other words, a particular portfolio may suffer from frequent exposure to the wholesale power market, but due to a low purchase amounts during these events receive an overall favorable CEUE score. Staff recommends that the Commission require PGE to perform the analyses required by Guideline 11 in PGE's next IRP Update.

PGE denies NWEC's assertion that PGE's EUE metric is independent of the resource mix of IRP portfolios. PGE asserts that this metric "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.[71]

2. Commission Resolution

IRP Guideline 11 specifically requires electric utilities to provide measures of expected and worst-case unserved energy for the top-performing resource portfolios. PGE's EUE and CEUE metrics measure a portfolio's overall exposure to the wholesale power market, not annual unserved energy. PGE correctly points out that its metrics also reflect the forced outage rates and mean times to repair of the resources included in the portfolios. However, we cannot tell whether differences in outage rates and repair times impact the likelihood and amount of unserved energy. It is important to be able clearly distinguish between a portfolio's market exposure and its level of expected unserved energy.

This gap in the metrics used by PGE does not impact on our decisions in this IRP. In its 2009 IRP, PGE constructed its resource portfolios to meet specific energy and capacity targets. With a few noted exceptions, all of PGE's resource portfolios reflect similar levels of wholesale market exposure. Since all the portfolios have roughly the same market exposure, differences in the EUE metric largely reflect difference in the portfolios' overall generation outage rate.

We direct PGE to work with Staff, NWEC, and other parties in its next IRP cycle to develop reliability metrics that measure unserved energy. We recognize that this may require parties to estimate the depth of the wholesale power market over the IRP planning period.

[71] PGE's Aug 10, 2010 at 34, *citing* its 2009 IRP at 245-247.

III. CONCLUSION

PGE's 2009 IRP reasonably adheres to the principles of resource planning established in Orders No. 89-507 and 07-002 and is acknowledged with the following requirements:

In its next IRP, PGE must:

1. Include an updated benefit-cost analysis of the Cascade Crossing transmission project. For the updated analysis, PGE shall update its assumptions about project configuration, capital cost, path rating, wheeling revenues, and equity participation, and conduct sensitivity analyses that address any uncertainty about capital cost, path rating, levels of equity participation, and levels of wheeling revenues.

2. Provide the following:

   (a) Its estimated cost per MW of capacity savings by Demand Response (DR) type (i.e., firm vs. non-firm resources), and projected MW acquisitions by DR type for the next 5 years,

   (b) A discussion of the steps it is and will be taking to evaluate DR in the next IRP, and

   (c) An updated action plan for assessing (e.g., plans for pilot programs) and acquiring DR for the next 3 years.

3. Consider Conservation Voltage Reduction (CVR) for inclusion in its best cost/risk portfolio and identify in its action plan steps it will take to achieve any targeted savings.

In its next IRP Update and in its next IRP planning cycle, PGE must:

1. Include a Wind Integration Study that has been vetted by regional stakeholders.

2. Evaluate the use of unbundled RECs in its strategy to meet RPS requirements for the entire planning period.

3. 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.

IV. ORDER

IT IS ORDERED that:

1. The 2009 Integrated Resource Plan filed by Portland General Electric Company is acknowledged with the requirements set forth in this order.

2. Portland General Electric Company will file its next Integrated Resource Plan no later than November 19, 2012.

Made, entered, and effective NOV 23 2010.

Ray Baum
Chairman

John Savage
Commissioner

Susan K. Ackerman
Commissioner

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-18

IDAHO POWER COMPANY

ATTACHMENT NO. 4

Name of non-regulatory SIP revision	Applicable geographic area	State submittal date	EPA approval date	Additional explanation
* *	*	*	* *	*
8-Hour Ozone Maintenance Plan and 2002 Base Year Emissions Inventory.	Tioga County	9/28/06, 11/14/06	7/6/07, 72 FR 36892	
* *	*	*	* *	*

(2) * * *

Name of source	Permit No.	County	State submittal date	EPA approval date	Additional explanation/§ 52.2063 citation
USX Corp./US Steel Group-Fairless Hills.	09–0006	Bucks	8/11/95, 11/15/95	4/09/96, 61 FR 15709.	52.2036(b); 52.2037(c); source shutdown date is 8/1/91.
* *		*	*	*	* *
Rockwell Heavy Vehicle, Inc.-New Castle Forge Plant.	37–065	Lawrence	4/8/98	4/16/99, 64 FR 18818.	52.2036(k); source shutdown date is 4/1/93.
* *		*	*	*	* *
Mercersburg Tanning Co.	28–2008	Franklin	4/26/95	3/12/97, 62 FR 11079.	52.2037(h); 52.2063(c)(114)(i)(A)(3) & (ii)(A).
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[FR Doc. 2011–16636 Filed 7–1–11; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R10–OAR–2011–0035; FRL–9425–3]

Approval and Promulgation of Implementation Plans; State of Oregon; Regional Haze State Implementation Plan and Interstate Transport Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is approving portions of a State Implementation Plan (SIP) revision submitted by the State of Oregon on December 20, 2010, as meeting the requirements of Clean Air Act (CAA) section 110(a)(2)(D)(i)(II) as it applies to visibility for the 1997 8-hour ozone and 1997 particulate matter ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS). EPA is also approving portions of the revision as meeting certain requirements of the regional haze program, including the requirements for best available retrofit technology (BART).

DATES: *Effective Date:* This final rule is effective August 4, 2011.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–R10–OAR–2010–0035. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the State and Tribal Air Programs Unit, Office of Air Waste and Toxics, EPA Region 10, 1200 Sixth Avenue, Seattle, WA 98101. EPA requests that if at all possible, you contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 8 a.m. to 4 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Keith Rose, EPA Region 10, Suite 900, Office of Air, Waste and Toxics, 1200 Sixth Avenue, Seattle, WA 98101.

SUPPLEMENTARY INFORMATION:

Definitions

For the purpose of this document, we are giving meaning to certain words or initials as follows:

(i) The words or initials *Act, CAA,* or *Clean Air Act* mean or refer to the Clean Air Act, unless the context indicates otherwise.

(ii) The words *EPA, we, us* or *our* mean or refer to the United States Environmental Protection Agency.

(iii) The initials *SIP* mean or refer to State Implementation Plan.

(iv) The words *Oregon* and *State* mean the State of Oregon.

Table of Contents

I. Background Information

On July 18, 1997, EPA promulgated new NAAQS for 8-hour ozone and for fine particulate matter ($PM_{2.5}$). This action is being taken, in part, in response to the promulgation of the 1997 8-hour ozone and $PM_{2.5}$ NAAQS. Section 110(a)(1) of the CAA requires states to submit a SIP revision to address a new or revised NAAQS within 3 years after promulgation of such standards, or within such shorter period as EPA may prescribe. Section 110(a)(2) lists the elements that such new SIPs must address, as applicable, including section 110(a)(2)(D)(i), which pertains to interstate transport of certain emissions.

Section 110(a)(2)(D)(i) of the CAA requires that a SIP must contain adequate provisions prohibiting any source or other type of emissions activity within the state from emitting any air pollutant in amounts which will: (1) Contribute significantly to nonattainment of the NAAQS in any other state; (2) interfere with maintenance of the NAAQS by any other state; (3) interfere with any other state's required measures to prevent significant deterioration of air quality; or (4) interfere with any other state's required measures to protect visibility. This action addresses the fourth prong, section 110(a)(2)(D)(i)(II).

In the CAA Amendments of 1977, Congress established a program to protect and improve visibility in the national parks and wilderness areas. See CAA section 169(A). Congress amended the visibility provisions in the CAA in 1990 to focus attention on the problem of regional haze. See CAA section 169(B). EPA promulgated regulations in 1999 to implement sections 169A and 169B of the Act. These regulations require states to develop and implement plans to ensure reasonable progress toward improving visibility in mandatory Class I Federal areas [1] (Class I areas). 64 FR 35714 (July 1, 1999); see also 70 FR 39104 (July 6, 2005) and 71 FR 60612 (October 13, 2006).

On December 20, 2010, the State of Oregon submitted to EPA a State Implementation Plan (SIP) revision addressing the interstate transport requirements for visibility for the 1997 ozone and $PM_{2.5}$ NAAQS, *see* CAA § 110(a)(2)(D)(i)(II), and the requirements of the Regional Haze program at 40 CFR 51.308. (Regional Haze SIP submittal).

On March 8, 2011, EPA published a notice in which the Agency proposed to approve the Oregon SIP revision as meeting the requirements of both section 110(a)(2)(D)(i)(II) of the CAA and the Regional Haze requirements set forth in sections 169A and 169B of the Act and in 40 CFR 51.300–308 with the exception of Chapter 11, Oregon Reasonable Progress Goal Demonstration and Chapter 12, Long-Term Strategy. 76 FR 12651. (Notice of Proposed Rulemaking or NPR). For Oregon's Reasonable Progress Goal Determination and Long-Term Strategy, EPA did not propose taking any action.

[1] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the Clean Air Act, EPA, in consultation with the Department of the Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the Clean Air Act apply only to "mandatory Class I Federal areas." Each mandatory Class I Federal area is the responsibility of a "Federal Land Manager." 42 U.S.C. 7602(i). When we use the term "Class I area" in this action, we mean a "mandatory Class I Federal area."

II. Response to Comments

EPA received a number of comments on the proposed action to approve certain elements of the Regional Haze SIP submittal. Comments in support were received from: The Citizens' Utility Board of Oregon; International Brotherhood of Electrical Workers Local 125; Morrow County; and Portland General Electric Company (PGE). Adverse comments were received by two entities: The National Parks and Conservation Association (NPCA); and Pacific Environmental Advocacy Center (PEAC). The comments submitted by NPCA incorporated multiple comments which were previously submitted to Oregon Department of Environmental Quality (ODEQ) on some of the prior proposals the State was previously considering. Some of these comments related to options, closure timeframes or evaluations which were previously considered by ODEQ but were not included in the final Regional Haze SIP submission. Accordingly, because these now superseded aspects of ODEQ's BART analysis or determination are not before EPA, a response to the comments about those options is not necessary. The following discussion summarizes and responds to the relevant comments received on EPA's proposed SIP action and explains the basis for EPA's final action.

Comment: The Citizens' Utility Board commented that the ODEQ BART rules for the PGE coal-fired electric power plant at Boardman, Oregon (PGE Boardman or Boardman facility) allow for cost effective pollution controls which will reduce air pollution generated by the facility, including air pollutants which contribute to haze in Class 1 areas. The commenter states that the rules also require the Boardman facility to be shut down by December 31, 2020 and the shut down allows the State of Oregon to move forward with its goals to reduce carbon emissions statewide and will protect utility customers from the costs and risks that will be associated with carbon regulation. The commenter further stated that the Best Available Retrofit Technology (BART) rules approved by the ODEQ are the product of several years of work resulting from a collaborative process involving state agencies, environmental organizations, consumer groups, local governments, and other stakeholders. The rules result in significant reductions in air pollution, while allowing Oregon to pursue important state policies targeted towards reducing carbon emissions, and keeping electric rates affordable.

Response: EPA acknowledges the comment and notes that there will be a significant reduction in NO_X and SO_2 from the Boardman facility due to the BART controls for those pollutants, and the further reasonable progress limits for SO_2 in 2018. Also, ceasing to use coal at the Foster-Wheeler boiler by end of 2020, will result in a additional reduction of NO_X, SO_2, and carbon dioxide emissions from the facility and significant cumulative visibility improvement in all impacted Class I areas.

Comment: International Brothers of Electrical Workers Local 125 commented that the Boardman facility is more than an electrical generating plant and that the city of Boardman and county of Morrow are dependent on this a facility for a substantial portion of its revenue. Boardman's citizens and Morrow County's resident recognize that the facility will cease using coal by the end of 2020, but are hopeful that alternative fuel sources will be approved to continue operations beyond 2020.

Response: EPA recognizes the facility's importance to the community. The approved rules do not prevent the facility owners from using alternate fuel or from constructing a new power source. If the Boardman facility is powered with alternative fuels or if a new facility is constructed all applicable CAA requirements, including New Source Performance Requirements (NSPS) and Prevention of Significant Deterioration (PSD) emission control requirements, must be met. The emission netting basis and plant site emission limits (PSELs) used in determining whether a modification to facility must meet PSD requirements, will be reduced to zero when the Foster-Wheeler boiler at the facility permanently ceases to burn coal. OAR 340–223–0030(1)(e).

Comment: Morrow County commented that they support EPA's approval of Oregon's Regional Haze SIP submittal and stated that the 10 year timeframe in the BART rule provides adequate time to put reliable replacement generation in place, protects this region and the state from the economic blow that would result from an earlier closure and is an appropriate balance of environmental and economic interests of Oregon and its citizens. The County further stated that the SIP accomplishes their wish to have environmental standards in place that will preserve the beauty of the area for future generations by reducing emission of NO_X, SO_2, and mercury, during the plant's remaining lifetime and ending all coal-related emissions from the Boardman facility at least 20 years ahead of schedule.

Response: EPA acknowledges this comment.

Comment: PGE commented that it believes that the ODEQ BART rules for the Boardman facility achieve the proper balance of environmental benefits, the cost to customers and the reliability of the PGE electrical power system. PGE states it found that it is possible to secure greater environmental benefits with a better balance of cost and risk by transitioning the Boardman facility away from coal at least 20 years ahead of schedule. PGE believes that the ODEQ Boardman BART rule includes significant and cost-effective emission control measures to improve visibility and ensure that the Boardman plant will cease coal-firing by December 31, 2020.

Response: EPA believes that the BART controls required for PGE Boardman will result in a significant reduction in haze that impacts Class I areas through 2020. Then, ceasing to burn coal at the facility will result in additional and significant reductions in SO_2 and NO_X emissions from Boardman at that time, and well as substantial reductions in carbon dioxide emissions. Further, ceasing to burn coal by no later than December 31, 2020, will result in cumulative visibility improvements in all 14 impacted Class I areas. See Regional Haze SIP submittal, Appendix D at D–171.

Comment: Comments were submitted claiming an inappropriate double-counting of "remaining useful life" by ODEQ to justify lesser pollution control requirements as BART for the Boardman facility.

Response: ODEQ did not double-count the remaining useful life of the plant in the PGE Boardman BART analysis. As ODEQ explained, closure of the plant is not, by itself, considered BART. Rather, the closure date establishes the remaining useful life of the plant which is used to determine the cost effectiveness of the various control technologies. See Regional Haze SIP submittal, Appendix D at D–125. See also Appendix Y to Part 51—Guidelines for BART Determinations Under the Regional Haze Rule (BART Guidelines), Section D. step 4.k.1. (70 FR 39156 (July 6, 2005)). A decision to cease burning coal by 2020 shortens the expected useful life of the coal-burning Foster-Wheeler boiler by 20 years when compared to its expected useful life of 2040. ODEQ documented its method for incorporating remaining useful plant life in determining cost effectiveness of control technologies. See Regional Haze SIP submittal, Appendix D at D–125 and D–131. The BART Guidelines specifically provide that the remaining useful life of a source may affect the annualized costs of retrofit controls and explains that "where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations." 70 FR 39169. Thus, ODEQ appropriately applied the BART Guidelines when it considered the remaining useful life of the Foster-Wheeler boiler when evaluating the cost effectiveness of the control technologies. In addition, EPA notes that ODEQ's conclusion regarding cost effectiveness for SO_2 controls, specifically Semi-dry Flue Gas Desulfurization (SDFGD) versus Dry Sorbent Injection (DSI) technologies, varied appropriately depending on the plant closure date. See EPA Assessment of ODEQ Determination of Best Available Retrofit Technology for the PGE Coal Fired Power Plant in Boardman, Oregon (EPA Boardman BART Assessment) January 18, 2011.

Comment: One comment stated that a compilation of BART analyses across the United States reveals that the average cost per deciview (dv) proposed by either a state or a BART source is $14 to $18 million, with a maximum of $51 million per dv proposed by South Dakota at the Big Stone power plant. The commenter noted that ODEQ has chosen $10 million/dv as a cost criterion, which is somewhat below the national average.

Response: ODEQ selected a dollars/dv cost effectiveness threshold of $10 million/dv based on what it considered the most relevant cost effectiveness figures available from similar coal-fired power plants in other parts of the country. See Regional Haze SIP submittal, Appendix D—Table 16 (D–137) for the estimated dollars/dv of the various control technologies. EPA notes that the comment is consistent with EPA's review of dollars/dv cost effectiveness data compiled by the National Park Service (NPS) available for a variety of coal-fired facilities located across the country. The NPS data show that ODEQ's dollar/dv threshold is below the average cost for BART NO_X and SO_2 control technologies selected for other coal-fired power plants in the country. In EPA's view, however, the dollars/dv metric is a difficult one to apply consistently across BART sources given the variability in the number of Class I areas impacted by emissions from a BART source and the number of days of impacts at each area. In assessing the reasonableness of a state's BART determination, EPA does not consider it appropriate to focus on a bright-line threshold such as a dollars/dv cost effectiveness threshold but rather on the full range of relevant factors. In reviewing the BART determination for the Boardman facility, EPA has accordingly taken into account not only ODEQ's analysis of dollars/dv, but also the range of visibility impacts associated with the various control options.

Comment: One comment expressed concern with the way in which the incremental cost analysis is used by ODEQ. It stated that to use incremental costs properly, they must be compared to incremental costs for similar situations.

Response: The Regional Haze SIP submittal shows that that ODEQ estimated the incremental cost and average cost effectiveness of the various control options considered in its cost analysis for determining BART. ODEQ first calculated the average cost effectiveness of each technology, and then calculated the incremental cost of going from the most cost effective technology to each of the more stringent technically feasible control technologies. See Regional Haze SIP submittal, Appendix D—Table 8 at D–132 and Cost effectiveness table on D–168. The approach used by ODEQ to determine average and incremental cost effectiveness is consistent with the procedure outlined in the BART Guidelines. See 70 FR 39167. Given the source-specific nature of a BART determination and the emphasis not only on the costs of control, but other factors such as the degree of visibility improvement resulting from the use of controls and the remaining useful life of the facility, comparisons of incremental costs across sources are often not meaningful in making BART determinations.

Comment: Multiple comments were submitted concerning the cost effectiveness calculations. The comments expressed concern regarding the dismissal of controls that are cost-effective even with the State's $7,300/ton and $10 million/dv thresholds claiming that semi-dry flue gas desulfurization (SDFGD), selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were eliminated from consideration as BART for PGE Boardman through inappropriately inflated costs, inclusion of costs not allowed by EPA's Cost Control Manual, underestimated control effectiveness, and arbitrarily and shortened equipment life due to excessively long assumed installation times.

Response: As explained in the SIP submittal, ODEQ evaluated and considered the costs, control efficiencies of the various control technologies, and expected equipment life in its BART determination. ODEQ used an independent contractor (ERG) to evaluate PGE's cost estimates for the Boardman facility and concluded that while PGE's estimates were significantly higher than ERG's, PGE's estimates better reflected real world costs, and were appropriate for the PGE Boardman BART analysis. More specifically, ERG concluded that the actual cost of retrofits is, in general, higher than the estimates provided by the EPA's Cost Control Manual. ODEQ explained that difference is due to a dramatic increase is labor and material costs in recent years. See Regional Haze SIP submittal, Attachment 7.2, ODEQ response to comments, I.1.a–c, for more detail.

In reviewing ODEQ's BART determination, EPA recognized that the cost estimates ODEQ relied on included two capital cost line items that are not normally included when using the EPA Cost Control manual. The effect of including these two line items is that the capital costs are likely "at the high end" of the capital cost range estimate. See EPA Boardman BART Assessment at 2. To assess the impact of ODEQ's decision to include these items in the cost estimate, EPA further evaluated the cost effectiveness value for SDFGD without including the two capital cost line items, and concluded that the cost effectiveness of SDFGD would drop from $5,535/ton to $4,810/ton. Although EPA considers the $4,810/ton to better reflect the true cost of SDFGD, we conclude that the $725/ton difference between the two estimates would not materially affect ODEQ's evaluation. EPA notes that the incremental visibility improvement between SDFGD and DSI–1 (0.4 lb/mmBtu) would only be 0.4 dv at the most impacted Class I area. Additionally, EPA found that with an SO_2 limit of 0.3 lb/mmBtu in 2018, the incremental visibility improvement between the two control technologies would only be 0.26 dv in the most impacted Class I area. In addition, while SDFGD would achieve a cumulative visibility improvement of 10.6 dv in all impacted Class I areas and DSI–1 [2] would achieve a cumulative visibility improvement of 7.0 dv and DSI–2 [3] would achieve a cumulative improvement of 9.3 dv in 2018, when the facility ceases to burn coal at the end of 2020, the cumulative visibility improvement would be 31.46 dv. See Regional Haze SIP submittal, Appendix D at D–137, 168 and 171. When choosing between the two technologies, it is reasonable for the state to consider the sizable capital cost difference between SDFGD and DSI, and the relatively small incremental visibility improvement between the two technologies in light of the shutdown of the unit in 2020. In EPA's view, ODEQ's final selection of BART would not have changed even if the cost effectiveness had been adjusted to reflect the EPA Cost Manual.

Regarding the comments concerning control effectiveness of SCR, SNCR, and SDFGD technologies, ODEQ determined the control effectiveness of these control options by evaluating actual emissions data from other sources employing similar types controls, taking into consideration that BART limit must be achieved at all times for a retrofit installation at Boardman. ODEQ's evaluation determined that the Boardman facility could not achieve the lower emission rate suggested by the commenter. See Regional Haze SIP submittal, Appendix D at D–14 through D–18, and Attachment 7.2, ODEQ response to comments 1I.1.b.

Comment: A commenter notes that on September 1, 2010, Oregon released a proposed rulemaking for public comment that included BART requirements for PGE Boardman based on a variety of closure dates, including 2020. The comment claims that the September 2010 proposal required installation of SDFGD and SNCR for a 2020 shutdown but that the requirements for a 2020 closure date were relaxed significantly in the plan EPA proposes to approve. The commenter does not believe there is sufficient justification for this relaxation of BART and states the relaxation appears arbitrary.

Response: As mentioned above, EPA's action relates to the BART determinations contained in the Regional Haze Plan that was submitted to EPA on December 20, 2010. EPA explained the basis for its decision to approve ODEQ's BART determination in the notice of proposed rulemaking. 76 FR at 12660–12662. Although ODEQ may have considered establishing more stringent BART emission limits at an earlier point, this does not provide a basis for disapproving its final BART determination.

Comment: A commenter stated that it is unclear whether the current regulatory language proposed by ODEQ would actually result in the "closure" of the Boardman facility because each closure option states that it only applies to the "Foster-Wheeler boiler" at Boardman. To ensure no other coal-fired boiler could be installed at Boardman the commenter requested ODEQ to strike the commercial name of the boiler from OAR 340–223–0020 through OAR 340–223–0090 and replace it with either "any coal-fired boiler" or "the Boardman coal-fired power plant."

Response: The State rules are clear in that they apply to the Foster-Wheeler boiler which is the only coal-fired unit at the Boardman facility. The rules do not prevent the plant owners from applying for a permit to construct a new power plant at the facility or to use the existing equipment with different fuel. See Oregon Regional Haze SIP submittal Attachment 1.1 at 8–9. However any new facility or change in the operations would need to be permitted in compliance with the CAA requirements. Further, the rules explain that notwithstanding the definition of netting basis and the process for reducing plant site emission limits (PSEL) in the Oregon rules, the netting basis and the PSEL are reduced to zero on the date which the boiler permanently ceases to burn coal. See OAR 340–223–0030(1)(e). Thus, as ODEQ explained to the Environmental Quality Commission, "Any new facility or repowering of the existing coal-fired boiler would be permitted as a new facility without relying on the reductions from the existing plant and in compliance with all applicable state and federal requirements, including modern air pollution controls and air quality impact analysis." See Regional Haze SIP submittal, Attachment 1.1 at 9.

Comment: Multiple commenters explained that if ODEQ decides that the SO_2 emission limit, based on DSI, is BART for PGE Boardman, it should require PGE to design and install the DSI system to achieve 90% efficiency and require that PGE optimize its effectiveness for the duration of its operation.

Response: ODEQ established SO_2 BART limits for the Boardman facility based on an estimated 35% minimal efficiency of DSI in removing SO_2 from the flue gas. A similar comment regarding DSI efficiency was made to ODEQ during the State public comment period. In response ODEQ stated:

[2] DSI–1 is defined as the initial DSI system performance that would achieve an SO_2 emission limit of 0.4 lbs/mmBtu by July 1, 2014.

[3] DSI–2 is defined as the DSI system performance that would achieve an SO_2 emission limit of 0.3 lbs/mmBtu by July 1, 2018.

"ODEQ is not aware of a DSI system, such as proposed for the PGE Boardman Plant, to have been installed on a similar sized unit. DSI has been used on smaller units that also included fabric filters, which both contribute to improved efficiency of the DSI system. ODEQ's proposal relies on the existing ESP and does not include the installation of a fabric filter, which would cost over $100 million. In addition, the ducts between the air heater and the ESP are much larger at the Boardman Plant. It is more difficult to adequately disperse the sorbent reagent in larger ducts and still maintain enough residence time for the sorbent to react with the SO_2. [A] thirty five percent efficiency is probably a little conservative, but a BART limit should be achievable at all times." Regional Haze SIP submittal, Attachment 7.2 response to comment I.6.a.

EPA considers ODEQ's response regarding the uncertainties associated with the use of DSI to be reasonable.

Comment: One comment stated that DSI for PGE Boardman for the shutdown within five years of EPA approval of the SIP may well be an appropriate cost effective technology choice capable of reducing SO_2 emissions in a manner consistent with BART requirements. Similarly, a commenter states that ODEQ should require that PGE install DSI "as expeditiously as practicable" and contends it could be installed in a year's time.

Response: As explained above, ODEQ determined that DSI is a cost effective control technology for SO_2. The Oregon BART rule at OAR 340–223–0030 (1)(b)(A) requires that the Boardman facility achieve an SO_2 emission limit of 0.4 lbs/mmBtu by July 1, 2014, about two years ahead of the five-year maximum time allowed by the CAA for the installation of BART. As ODEQ explains, "The proposed compliance date [of July 1, 2014] allows PGE three years to design the DSI system and conduct the pilot study, which may involve evaluation of several types of sorbent materials and injection locations, along with particulate matter stack testing." See Regional Haze SIP submittal, Attachment 7.2, response to comment I.7. Given the uncertainties associated with the use of DSI on a plant such as Boardman, installing DSI in this timeframe satisfies the requirement of "as expeditiously as practicable" and is within the timeframe specified in the CAA.

ODEQ determined that the Boardman facility need install any additional emission controls if the Foster-Wheeler boiler is shut down within five years of approval of the SIP. ODEQ did not consider DSI as a required control technology for this scenario. See Regional Haze SIP submittal, Appendix D at D–142. EPA agrees with ODEQ's conclusion that it would be unreasonable to require the installation of DSI for such a short period of operation before shutting down.

Comment: One comment stated that the capital and operating costs of DSI for Boardman were overstated. Some comments explained that although ODEQ has not provided sufficient data on the costs of DSI, it is possible that DSI could also meet ODEQ's cost-effectiveness threshold, even if used for only a few years as in the case were the Boardman facility were to shut down within five years of EPA final approval of the SIP.

Response: ODEQ's analysis for determining the capital and direct annual costs for DSI are described on pages D–130–131 of Appendix D of the Regional Haze SIP submittal. EPA's Boardman BART Assessment acknowledged that PGE's capital cost estimates for various control technologies are "likely at the high end of the range for capital cost estimates," but as discussed above, even if the cost estimates are at the high end, considering the cost differential between DSI and SDFGD, and given the visibility improvements associated with selecting DSI based on an early shut down, the variation in cost estimates was not determinative. Therefore, EPA believes that the methods used by ODEQ to determine effectiveness and cost of DSI, and a determination not to require DSI if the Boardman facility ceases to burn coal within five years of EPA's approval, are reasonable and within the State's discretion. See also the response to comment above.

Comment: One comment stated that DSI is a technically feasible control technology at PGE Boardman. This comment explained that (1) the size of the coal-fired unit is inconsequential as to whether DSI is technically feasible, and (2) while DSI is not in widespread use on larger boilers like the Boardman facility, that is most likely due to availability of sorbents, costs, and SO_2 control effectiveness when compared to other SO_2 control technologies like semi-dry or wet scrubbers, not technical feasibility.

Related comments suggest that it is improper for ODEQ to discard DSI as technically infeasible merely because its installation triggers addition legal obligations under the Clean Air Act (or State law). In the commenter's view, ODEQ cannot conclude that DSI is technically infeasible because it would interfere with PGE's compliance with state mercury reduction goals, or result in adverse impacts to the particulate matter air quality standards. The comment states that as a legal matter PGE must comply with requirements associated with Regional Haze, and those intended to prevent significant deterioration of air quality and any requirements to reduce hazardous pollutants such as mercury. In the commenter's view, even if DSI were genuinely technically infeasible, PGE would not be entitled to the de facto exemption from BART that it requests because the ODEQ has an obligation to identify, and prescribe, a technically feasible BART limit.

Response: As explained above, ODEQ determined that DSI is technically feasible for PGE Boardman. Although ODEQ was not aware of a similar sized unit with a DSI system, this control technology has been used on smaller units that also included fabric filters which contribute to improved efficiency of the DSI system. However, ODEQ's BART determination does not require the installation of a new fabric filter system, which would cost about an additional $100 million, but instead relies on the use of the existing ESP at the Boardman facility. Furthermore, there is additional question regarding DSI performance because of the size of the ducts between the air heater and the ESP. These ducts are much larger at the Boardman Plant than the ducts on smaller power plants where DSI has been demonstrated. This adds to the uncertainty in DSI performance because it is more difficult to adequately disperse the sorbent reagent in larger ducts and still maintain enough residence time for the sorbent to react with the SO_2. Thus, there is some uncertainty as to how well DSI will work on this particular facility. See Regional Haze SIP submittal, Appendix D at D–129, D–169 and D–170 (ODEQ's basis for projected DSI system efficiency).

Although ODEQ concluded that DSI is technically feasible, it also took into consideration that DSI at this size and type of facility may result in unacceptable levels of PM or mercury emissions. This could result in potential additional costs if the levels of these pollutants were high enough to require additional controls. Specifically, ODEQ recognized that a significant increase in PM2.5 emissions was a possible outcome of installing DSI, and that if this occurred, the installation would be subject to the PSD requirements. The resulting BACT or air quality impact analysis would require additional controls which would increase the cost of DSI. Regional Haze SIP submittal, Appendix D at D–142 and D–170. Thus, rather than avoiding other legal requirements, ODEQ considered them in its overall cost effectiveness evaluation of the technology. ODEQ did not exclude the technology because it might trigger other legal obligation but considered them in the overall evaluation of what was the most reasonable BART for this facility.

Comment: One commenter stated that Oregon did not appropriately consider the lower emission limitation of 0.3 lb/mmBtu (DSI–2) as BART, but instead only considered it to meet reasonable further progress by 2018. The commenter explained that the DSI–2 limitation was not identified as technologically infeasible or cost prohibitive for BART, and that ODEQ has provided no reason why the study of DSI–2 cannot be conducted "as expeditiously as practicable" but no later than five years after EPA approves the state SIP.

Response: ODEQ determined that due to uncertainties associated with DSI–1 performance at a large coal fired-facility the size of Boardman without a baghouse, the higher, more conservative limit of 0.40 lb/mmBtu could be achieved with a high degree of certainty in 2014, whereas the lower limit of 0.3 lb/mmBtu would not be achieved with DSI–2 until 2018, when future refinements in the DSI system performance could be achieved, possibly in combination with ultra-low sulfur coal or supplemental fuels, such as biomass. Regional Haze SIP submittal, Appendix D at D–169– D–170; 76 FR 12662. See also response to comment above.

Comment: One commenter stated that loopholes in Oregon's Administrative Rules (OAR 340–223–0010 through 340–223–0080) included provisions that would inappropriately remove the requirement for DSI. In the commenter's view the condition under which DSI would not be required, including a post-BART determination of technical infeasibility or the triggering of additional CAA obligations should not be allowed to preclude the installation of BART, which is by definition technically feasible. The commenter also asks that in approving Oregon's SIP submittal, EPA interpret the conditions contained in OAR 340–223–0030(3) as requiring EPA approval or concurrence with ODEQ's determinations prior to implementation of relaxed standards. Additionally, a commenter questions whether the provision would require or allow any public comment on ODEQ's determination that DSI–1 or DSI–2 is technologically infeasible, would inhibit compliance with Oregon's mercury rules, or would trigger PSD applicability.

Response: As explained above, ODEQ determined that DSI is a technically feasible SO_2 control technology for PGE Boardman and that it can achieve 0.4 lb/mmBtu at a removal efficiency of about 35%. Regional Haze SIP submittal, Appendix D at D–127–128. While ODEQ determined that DSI was technically feasible, it also acknowledged that the technology has only been demonstrated at smaller boilers than the one at the Boardman facility.[4] Thus, the State determined it was appropriate to require additional studies. The rules being approved today provide that technical studies to evaluate the SO_2 limits, and the potential side effects of those limits, must be conducted in accordance with a plan that is preapproved by ODEQ. These studies will fully evaluate and review the effectiveness and use of DSI technology at this facility. See OAR 340–223–0030(2), see also Regional Haze SIP submittal, Attachment 7.2 at 17. The rules first establish a limit of 0.40 lb/mmBtu by July 1, 2014 and 0.30 lb/mmBtu by July 1, 2018. Then the rules describe the specific conditions under which the SO_2 limit of 0.40 lb/mmBtu or 0.30 lb/mmBtu may be exceeded. OAR 340–223–0030(3). Specifically, the rules provide that if upon completion of the specified pilot studies, the results shows that DSI is not capable of achieving the BART limit of 0.4 lb/mmBtu (between July1, 2014 and June 30, 2018) or 0.30 lb/mmBtu (between July 1, 2018 and December 31, 2020), or would prevent compliance with specified mercury limits or cause a significant air quality impact for PM10 or PM2.5, the SO_2 emission limit may be modified up to 0.55lb/mmBtu through a modification to the facility's Title V permit. The rule being approved today is clear as to what conditions must be satisfied in order for the source to exceed the 0.4 lb/mmBtu or 0.3 lb/mmBtu limits. The rule provides, that if applicable, the study may propose a limit that exceeds the 0.4 lb/mmBtu or 0.3 lb/mmBtu limits based on reduction of the sulfur dioxide emission limits to the maximum extent possible through the use of DSI or other SO_2 control system of equal or lower cost, including but not limited to the use of low sulfur coal, provided that the proposed emission limit may not exceed 0.55lb/mmBtu heat input as a 30-day rolling average. The conditions and parameters under which the 0.3 lb/mmBtu or 0.4 lb/mmBtu emission limits may be exceeded, are spelled out in the rule and were considered by EPA in its review of the proposed rule. Those conditions and parameters, including the alternate upper limit of 0.55 lb/mmBtu, are being approved today and additional approval by EPA is not necessary.

Regarding the commenter's concern relating to the opportunity for public input into this potential change in emission limits, the rule allows for the PGE Boardman's Title V operating permit to be modified to include a federally enforceable permit limit based on the performance of DSI demonstrated by the pilot study, as performed according to OAR 340–223–0030(2)(c). Thus, before the 0.4 lb/mmBbtu or 0.3 lb/mmBtu emission limits may be exceeded, the source would need to comply with the conditions in OAR 340–223–0030(3) including submitting a complete application for a Title V permit modification. The permit modification would be considered a significant permit modification under OAR 340–218–0180 and a category 3 permit under Oregon Title V rules. See OAR 340–218–0210(1). A category 3 permit is subject to the procedures in OAR 340–209–0030(3)(c) which include general public notice, opportunity for public comment and EPA review. In addition, the results of the pilot study, the technical basis and the recommended alternative limit would be provided to the public for review and comment during the Title V modification process.

Comment: The commenter also asks EPA to re-evaluate the environmental benefits from Oregon's SIP submittal based on the emission limit and reductions that EPA approval of the SIP would actually require: 0.55 lb/mmBtu, which the Oregon SIP submittal does require to be met, regardless of the results of the pilot studies.

Response: The visibility improvements to Class I areas impacted by PGE Boardman were based on the SO_2 and NO_X BART emission limits to be achieved by 2014, and on further reasonable progress emission limits for SO_2 achieved by 2018. The SO_2 BART limit of 0.40 lb/mmBtu is the applicable limit as of July 1, 2014 unless specific conditions are satisfied and ODEQ approves an alternate limit. See OAR 340–223–0030(2)(c)(E). Additionally, ODEQ explains that an alternate limit must not exceed 0.55 lb/mmBtu in order to achieve at least a 0.5 dv improvement

[4] EPA also recognizes some uncertainty regarding the effectiveness of this control at the Boardman facility. For example, EPA's "Air Pollution Control Technology Fact Sheet" states that "SO_2 removal efficiencies [of DSI] are significantly lower that wet systems, between 50% and 60% for calcium-based sorbents. Sodium- based dry sorbent injection into the duct can achieve up to 80% control efficiencies." EPA–452/F–03–034 at 5. EPA realizes that the proposed control limit of 0.4 lb/mmBtu is below the range cited in this fact sheet, but given the larger size of the Boardman boiler and the State's desire not to overload the existing ESP PM control system, EPA believes that the proposed emission limit is reasonable.

in visibility in Mt. Hood Wilderness Area. See Id. and the Regional Haze SIP submittal, Appendix D "Control Effectiveness" table at D–168 and text on D–170. Thus, the State considered the visibility improvements associated with a 0.55 lb/mmBtu and the additional analysis requested by the commenter is not necessary.

Comment: One commenter stated that visibility improvements and potential improvements in other non-air quality-related impacts in the region would occur as a result of the installation of SCR at the Boardman facility and should be taken into consideration in determining BART the facility. This commenter further explained that NO_X emissions can contribute to excess nitrogen in ecosystems, which can alter the chemical balance of the soils and waterbodies with serious consequences for plant and animal life. For these reasons, the commenter concluded, ODEQ must require installation of SCR and new low NO_X burners with overfire air as BART for the Boardman facility.

Response: The estimated visibility improvements that could be achieved over current conditions with each combination of technically feasible controls were taken into consideration in determining BART for Boardman. See 76 FR 12611. More specifically, ODEQ determined that LNB and MOFA are BART for NO_X because they are cost effective and provided a 1.45 dv improvement at Mt. Hood Wilderness Area (the most impacted Class I area) and a cumulative visibility improvement of 8.75 dv in all 14 impacted Class I areas. ODEQ determined that DSI is BART for SO_2 because it is cost effective and provides a significant (0.96 dv) improvement at Mt. Hood Wilderness Area and a 7.4 dv improvement in all impacted Class I areas by July 1, 2014. For further comparison of visibility improvement associated with the various control technologies and timeframes see the Regional Haze SIP submittal, Appendix D, at D–169–172. The contribution of the facility's NO_X emissions to excess nitrogen in ecosystems, were not taken into account in the PGE Boardman BART analysis. However, it would be extremely difficult to quantify, or even to qualitatively assess, the impacts of added nitrogen from one source on an ecosystem. The impacts of deposition related effects such as nutrient enrichment and eutrophication vary considerably across ecosystems. EPA does not consider it unreasonable for ODEQ to have not taken these impacts into account in making its BART determination.

Comment: One commenter urged the Department to consider and maintain the 2018 and five year closure options for the Boardman facility. The commenter requested that ODEQ also look at additional cost-benefit and technical analysis for the 2018 option.

Response: ODEQ's final Regional Haze SIP submittal includes rules which allow PGE Boardman to either cease burning coal within five years of EPA's approval of the rules or to cease burning coal by December 31, 2020. PGE must notify ODEQ in writing no later than July 1, 2014 if it chooses to cease coal burning within 5 years of this action. If it chooses that option, one set of emission limits apply; however, if it chooses to continue operating until December 31, 2020, more stringent emission limits apply. A 2018 shutdown option was considered by ODEQ but removed from the final SIP submittal because PGE indicated that it intended to operate the Boardman facility until the end of 2020, and because ODEQ has no authority to require a facility to shut down by a certain date under the BART Rule absent a commitment by the source to do so.

Comment: A commenter stated that the regulation should specify that if PGE continues to operate the Boardman facility as a coal-fired facility after its selected closure deadline the operating permit for the facility shall be deemed void. The commenter also requested that to avoid any uncertainty regarding the availability of relief due to non-compliance, the regulation should explicitly state that the state, EPA and citizens may apply for both injunctive and civil penalty relief.

Response: A violation of a federally enforceable state rule or permit is subject to liability as provided in section 113 of the CAA, 42 USC 7413, and would be addressed as appropriate under applicable state or federal law. Additional language to restate the existing authority is not necessary.

Comment: One commenter requested that EPA correct or remove certain factual statements that were included in the notice of proposed rulemaking. Specifically, the commenter requested changes to state that PGE Boardman is a 617 megawatt (MW) plant instead of 584 MW plant and that it commenced construction on "December 6, 1979" instead of in "1975".

Response: EPA agrees that the PGE Boardman coal fired power plant is capable of producing about 617 MW of electricity, not 584 MW. According to ODEQ's BART report, construction on the PGE Boardman plant began in 1975. However, the first air contaminant discharge permit from ODEQ to PGE for Boardman was dated December 6, 1979.

Comment: One commenter stated that for the five-year closure option at Boardman, ODEQ should require additional interim controls that would reduce emissions in the remaining five remaining years of operation.

Response: OAR 340–223–0080 provides alternate requirements in the event the owner elects to permanently cease burning coal within five years of EPA's SIP approval. Under this alternative, the NO_X emission limit of 0.23 lb/mmBtu applies beginning July 1, 2011, unless the source satisfies the requirements in OAR 430–223–0080(2)(a) and it is demonstrated by December 31, 2011, that the emission limit of 0.23 lb/mmBtu cannot be achieved with combustion controls, in which case the ODEQ may grant an extension to July 1, 2013. OAR 340–223–080(2)(a).

Comment: One commenter requested that the NO_X, SO_2 and PM emission limits for PGE Boardman include emission limits during startup and shutdown.

Response: The BART rules include do startup and shutdown emission limits for the Boardman facility. See OAR 340–223–0030(1)(d). These limits, which are three-hour rolling averages, are: Sulfur dioxide, 1.20 lb/mmBtu, Nitrogen oxide, 0.70 lb/mmBtu, and particulate matter emissions must be minimized to the extent practicable pursuant to approved startup and shutdown procedures in accordance with OAR 340–214–0310.

Comment: As stated above, NPCA incorporated into their comments a number of comment letters that had previously been submitted to ODEQ. Many of the comments contained in these letters relate to emission limits or comments about technologies associated with the "no closure" option provided in prior versions of OAR 340–223–0050, 0060, and 0070, and ODEQ's BART determination based on PGE operating the coal-fired boiler at the Boardman facility until 2040.

Response: The Oregon Regional Haze Plan submitted to EPA included revisions to the State's regional haze rules at OAR 340–223–0010 through 340–223–0080. In this action, EPA is taking final action to approve a revision to the Oregon SIP which incorporates OAR 340–223–0010 through 340–223–0080 and specifically includes OAR 340–223–0030. As provided in OAR 340–223–0050, and as explained in the notice of proposed rulemaking, upon EPA's final approval of OAR 340–223–0030, OAR 340–223–0060 and 340–223–0070 are repealed as a matter of law. 76 FR 12662–12663. Thus, compliance with the "no closure option" or operating until 2040 is no longer an alternative. Therefore, the BART determination associated with that option is no longer relevant and responses to comments regarding it are unnecessary.

III. Final Action

EPA is approving the BART measures in the Oregon Regional Haze plan as meeting the requirements of section 110(a)(2)(D)(i)(II) of the Clean Air Act with respect to the 1997 8-hour ozone and 1997 PM2.5 NAAQS. In addition, EPA is approving portions of the Oregon Regional Haze Plan, submitted on December 20, 2010, as meeting the requirements set forth in section 169A of the Act and in 40 CFR 51.308(e) regarding BART. EPA is also approving the Oregon submittal as meeting the requirements of 40 CFR 51.308(d)(2) and (4)(v) regarding the calculation of baseline and natural conditions for the Mt. Hood Wilderness Area, Mt. Jefferson Wilderness Area, Mt. Washington Wilderness Area, Kalmiopsis Wilderness Area, Mountain Lakes Wilderness Area, Gearhart Mountain Wilderness Area, Crater Lake National Park, Diamond Peak Wilderness Area, Three Sisters Wilderness Area, Strawberry Mountain Wilderness Area, Eagle Cap Wilderness Area, and Hells Canyon Wilderness Area, and the statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal Area.

IV. Oregon Notice Provision

Oregon Revised Statute 468.126, which remains unchanged since EPA last approved Oregon's SIP, prohibits ODEQ from imposing a penalty for violation of an air, water or solid waste permit unless the source has been provided five days' advanced written notice of the violation and has not come into compliance or submitted a compliance schedule within that five-day period. By its terms, the statute does not apply to Oregon's Title V program or to any program if application of the notice provision would disqualify the program from Federal delegation. Oregon has previously confirmed that, because application of the notice provision would preclude EPA approval of the Oregon SIP, no advance notice is required for violation of SIP requirements.

V. Scope of EPA Approval

Oregon has not demonstrated authority to implement and enforce the Oregon Administrative rules within "Indian Country" as defined in 18 U.S.C. 1151. "Indian country" is defined under 18 U.S.C. 1151 as: (1) All land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and including rights-of-way running through the reservation, (2) all dependent Indian communities within the borders of the United States, whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a State, and (3) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same. Under this definition, EPA treats as reservations trust lands validly set aside for the use of a Tribe even if the trust lands have not been formally designated as a reservation. Therefore, this SIP approval does not extend to "Indian Country" in Oregon. See CAA sections 110(a)(2)(A) (SIP shall include enforceable emission limits), 110(a)(2)(E)(i) (State must have adequate authority under State law to carry out SIP), and 172(c)(6) (nonattainment SIPs shall include enforceable emission limits).

VI. Statutory and Executive Orders Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a "significant regulatory action" and therefore is not subject to review by the Office of Management and Budget. For this reason, this action is also not subject to Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001). This action merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law. Accordingly, the Administrator certifies that this rule will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). Because this rule approves pre-existing requirements under state law and does not impose any additional enforceable duty beyond that required by state law, it does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4).

In addition, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the rule neither imposes substantial direct compliance costs on tribal governments, nor preempts tribal law. Therefore, the requirements of section 5(b) and 5(c) of the Executive Order do not apply to this rule. Consistent with EPA policy, EPA nonetheless provided a consultation opportunity to Tribes in Idaho, Oregon and Washington in letters dated January 14, 2011. EPA received one request for consultation, and we have followed-up with that Tribe. This action also does not have Federalism implications because it does not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999). This action merely approves a state rule implementing a Federal standard, and does not alter the relationship or the distribution of power and responsibilities established in the CAA. This rule also is not subject to Executive Order 13045 "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997), because it approves a state rule implementing a Federal standard.

In reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. In this context, in the absence of a prior existing requirement for the State to use voluntary consensus standards (VCS), EPA has no authority to disapprove a SIP submission for failure to use VCS. It would thus be inconsistent with applicable law for EPA, when it reviews a SIP submission, to use VCS in place of a SIP submission that otherwise satisfies the provisions of the CAA. Thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) do not apply. This rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by *September 6, 2011*. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Incorporation by reference, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Visibility, and Volatile organic compounds.

Dated: June 17, 2011.

Dennis J. McLerran,

Regional Administrator, Region 10.

Part 52, chapter I, title 40 of the Code of Federal Regulations is amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for Part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart MM—Oregon

■ 2. Section 52.1970 is amended by adding and reserving paragraph (c)(150), and adding paragraph (c)(151) to read as follows:

§ 52.1970 Identification of plan.

* * * * *

(c) * * *

(150) [Reserved]

(151) On December 20, 2010, the Oregon Department of Environmental Quality submitted a SIP revision to meet the regional haze requirements of Clean Air Act section 169A and the interstate transport requirements of Clean Air Act section 110(a)(2)(D)(i)(II) as it applies to visibility for the 1997 8-hour ozone NAAQS and 1997 $PM_{2.5}$ NAAQS.

(i) Incorporation by reference.

(A) December 10, 2010, letter from ODEQ to the Oregon Secretary of State requesting filing of permanent rule amendments to OAR 340–223.

(B) December 10, 2010, filed copy of State "Certificate and Order for Filing" verifying the effective date of December 10, 2010, for OAR 340–223–0010, OAR 340–223–0020, OAR 340–223–0030, OAR 340–223–0040, OAR 340–223–0050 and OAR 340–223–0080.

(C) The following revised sections of the Oregon Administrative Rules, Chapter 340:

(*1*) 340–223–0010 Purpose of Rules, effective December 10, 2010.

(*2*) 340–223–0020 Definitions, effective December 10, 2010.

(*3*) 340–223–0030 BART and Additional Regional Haze Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106), effective December 10, 2010.

(*4*) 340–223–0040 Federally Enforceable Permit Limits, effective December 10, 2010.

(*5*) 340–223–0050 Alternative Regional Haze Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106), effective December 10, 2010.

(*6*) 340–223–0080 Alternative Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL code 6106) Based Upon Permanently Ceasing the Burning of Coal Within Five Years of EPA Approval of the Revision to the Oregon Clean Air Act State Implementation Plan Incorporating OAR Chapter 340, Division 223, effective December 10, 2010.

(ii) Additional material.

(A) The portion of the SIP revision relating to statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal Area and the calculation of baseline and natural visibility conditions in Oregon Class I areas, and determination of current and 2018 visibility conditions in Oregon Class I areas.

(B) [Reserved]

■ 3. Section 52.1973 is amended by adding paragraph (g) to read as follows:

§ 52.1973 Approval of plans.

* * * * *

(g) *Visibility protection.* (1) EPA approves portions of a Regional Haze SIP revision submitted by the Oregon Department of Environmental Quality on December 20, 2010, and adopted by the Oregon Department of Environmental Quality Commission on December 9, 2010, as meeting the requirements of Clean Air Act section 169A and 40 CFR 51.308(e) regarding Best Available Retrofit Technology. The SIP revision also meets the requirements of 40 CFR 51.308(d)(2) and (d)(4)(v) regarding the calculation of baseline and natural conditions for the Mt. Hood Wilderness Area, Mt. Jefferson Wilderness Area, Mt Washington Wilderness Area, Kalmiopsis Wilderness Area, Mountain Lakes Wilderness Area, Gearhart Mountain Wilderness Area, Crater Lake National Park, Diamond Peak Wilderness Area, Three Sisters Wilderness Area, Strawberry Mountain Wilderness Area, Eagle Cap Wilderness Area, and Hells Canyon Wilderness Area, and the statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal Area. The SIP revision also meets the requirements of Clean Air Act section 110(a)(2)(D)(i)(II) as it applies to visibility for the 1997 8-hour ozone NAAQS and 1997 $PM_{2.5}$ NAAQS.

(2) [Reserved]

■ 4. Section 52.1989 is amended by adding paragraph (b) to read as follows:

§ 52.1989 Interstate Transport for the 1997 8-hour ozone NAAQS and 1997 $PM_{2.5}$ NAAQS.

* * * * *

(b) On December 20, 2010, the Oregon Department of Environmental Quality submitted a Regional Haze SIP revision, adopted by the Oregon Environmental Quality Commission on December 9, 2010. EPA approves the portion of this submittal relating to section 110(a)(2)(D)(i)(II) as it applies to visibility for the 1997 8-hour ozone NAAQS and 1997 $PM_{2.5}$ NAAQS. The SIP revision also meets the requirements of Clean Air Act section 169A and 40 CFR 51.308(e) regarding Best Available Retrofit Technology and the requirements of 40 CFR 51.308(d)(2) and (d)(4)(v) regarding the calculation of baseline and natural conditions for the Mt. Hood Wilderness Area, Mt. Jefferson Wilderness Area, Mt Washington Wilderness Area, Kalmiopsis Wilderness Area, Mountain Lakes Wilderness Area, Gearhart Mountain Wilderness Area, Crater Lake National Park, Diamond Peak Wilderness Area, Three Sisters Wilderness Area, Strawberry Mountain Wilderness Area, Eagle Cap Wilderness Area, and Hells Canyon Wilderness Area, and the statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal Area.

[FR Doc. 2011–16635 Filed 7–1–11; 8:45 am]

BILLING CODE 6560–50–P

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-11-18

IDAHO POWER COMPANY

ATTACHMENT NO. 5

Idaho Power Company

Summary of Revenue Requirement - Idaho

Boardman: 2012 Test Year

RATE BASE		
Electric Plant in Service		
Intangible Plant	$	-
Production Plant		-
Transmission Plant		-
Distribution Plant		-
General Plant		-
Total Electric Plant in Service	$	-
Less: Accumulated Depreciation	$	664,138
Less: Amortization of Other Plant		
Net Electric Plant in Service	$	(664,138)
Less: Customer Adv for Construction		
Less: Accumulated Deferred Income Taxes	$	(468,881)
Add: Plant Held for Future Use		
Add: Working Capital		
Add: Conservation - Other Deferred Prog		
Add: Subsidiary Rate Base		
TOTAL COMBINED RATE BASE	**$**	**(195,257)**

NET INCOME		
Operating Revenues		
Sales Revenues		
Other Operating Revenues		
Total Operating Revennues	$	-
Operating Expenses		
Operation and Maintenance Expenses		
Depreciation Expenses		1,328,276
Amortization of Limited Term Plant		
Taxes Other Than Income		
Regulatory Debits/Credits		
Provision for Deferred Income Taxes	$	(468,881)
Investment Tax Credit Adjustment		
Current Income Taxes		
Total Operating Expenses	$	859,394
Operating Income	$	(859,394)
Add: IERCO Operating Income		
Consolidated Operating Income	$	(859,394)
Rate of Return as filed		440%
Proposed Rate of Return		8.18%
Earnings Deficiency	$	843,422
Net-to-Gross Tax Multiplier		1.642
Revenue Deficiency	$	1,384,899
Firm Jurisdictional Revenue		834,980,775
REVENUE REQUIREMENT	$	836,365,674
Percentage Increase Required		0.17%