Comments on PGE 2009 Integrated Resource Plan Public Utility Commission of Oregon Docket No. LC 48

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Conclusion

Portland General Electric's ("PGE") recommended and alternate Action Plans would maintain the Company's dependence on the coal-fired Boardman plant for at least the next decade. For this reason, these plans entail excessive uncertainty and risk for PGE's ratepayers.

- Uncertainty as to the greenhouse gas emissions reductions that ultimately will be required as a result of federal, state or regional action and the timing and cost of compliance with likely future greenhouse gas regulations.
- Uncertainty about the impact of more stringent air emissions regulations and the cost of managing and storing coal combustion wastes.
- Uncertainty whether projected loads and energy sales will materialize.
- Uncertainty as to future coal prices and whether there will be supply disruptions that will affect plant performance and fuel prices.
- Uncertainty about the role that the Boardman plant will play as a baseload unit in the future.

The confluence of factors – economic recession, uncertainty about the details of federal greenhouse gas restrictions, impending costs associated with carbon emissions, tightening of air emissions requirements and standards for handling coal combustion by-products – means that this is a terrible time to make a significant investment in emissions controls at an existing coal-fired power plant. Such an investment would lock customers into paying for a course of action that could prove, and is indeed likely to prove, an ill-chosen option as greater certainty emerges over the next several years.

In light of these significant uncertainties, it would be better for the Company to adopt a resource plan that allows it to avoid large capital expenditures for the Boardman plant while offering the flexibility to modify course as circumstances change. PGE's recommended and alternate Action Plans that continue a near-term commitment to investments in the Boardman plant are the wrong choices in today's uncertain economic and regulatory conditions. Moreover, at the same time that there is a growing awareness of the dangers posed by global climate change, continuing to make large investments in the Boardman plant would lead to increases, not decreases, in PGE's annual greenhouse gas emissions.

Instead of spending hundreds of millions of dollars on Boardman, PGE should adopt a plan that relies on the substantial availability of energy efficiency, renewable resources and existing gas-fired capacity in the Northwest, as well as the widely accepted expectation that future natural gas prices will not be as high as was believed even two years ago. Such a plan will provide the flexibility that PGE and its ratepayers need and is a step in the right direction towards significantly reducing the Company's annual greenhouse gas emissions.

Finally, we have found that the economic analyses that PGE has presented in its 2009 Integrated Resource Plan ("IRP") and IRP Addendum are heavily biased in favor of the continued operation of the Boardman plant by a number of questionable assumptions regarding future natural gas prices, PGE's need for the capacity and energy from the Boardman plant, and the potential for entering into a mid- to long-term power purchase agreements for electricity generated at a gas-fired unit in the region. In fact, some of the key assumptions on which the results of PGE's IRP analyses are based have already been significantly modified since the IRP was issued in November 2009. Unfortunately, these substantial revisions have not been reflected in the analyses that the Company presented in the April 2010 IRP Addendum.

For these reasons:

1. The Commission should not approve PGE's requested expenditures for emissions controls for the Boardman coal plant.
2. The Commission should not approve PGE's recommended Action Plan which would allow the continued operation of the Boardman plant through the end of 2020.
3. The Commission should not approve PGE's alternate Action Plan that would allow PGE the option of continuing to operate the Boardman plant through 2040.

Summary of Findings

In particular, we have found:

Finding No. 1. PGE used unreasonably high natural gas prices in its IRP modeling analyses (both deterministic and stochastic) that biased the analyses against natural gas-fired alternatives and in favor of the continued operation of the Boardman plant

Finding No. 2. PIRA has significantly reduced its projected natural gas prices from the forecasts used in the PGE IRP analyses. These new forecasts confirm our conclusion that the gas prices used in the IRP analyses were unreasonably high.

Finding No. 3. PGE has not analyzed whether adding a new combined cycle natural gas-fired unit would be the lowest cost option if Boardman were retired at any time between 2014 and 2020.

Finding No. 4. PGE has not adequately considered the availability of a substantial amount of under-utilized gas-fired combined cycle and gas turbine capacity in and around the state of Oregon that could provide much, if not all, of the replacement energy if the Boardman plant were retired.

Finding No. 5. PGE overstates its need for the capacity and energy from the Boardman plant through the use of high load forecasts and by understating the potential for energy efficiency.

Finding No. 6. PGE has significantly reduced its long term energy and peak load forecasts in December 2009.

Finding No. 7. The results of PGE's IRP modeling analyses show that if PGE continues to operate the Boardman plant past 2020, its annual CO_2 emissions will be significantly higher in 2030 than they were in 2007. Even if PGE retires the Boardman within the next ten years, its annual CO_2 emissions in 2030 still will be higher than they were in 2007. Therefore, PGE must start to aggressively plan to achieve actual reductions in its CO_2 emissions rather than assuming, as it does in its IRP, that it will be able to continue emitting the same or higher levels of CO_2 by purchasing emissions allowances. Making large investments in the Boardman plant and continuing to operate the plant through 2040 would be a step in the wrong direction.

Finding No. 8. The results of PGE's stochastic analyses are distorted in favor of the continued operation of the Boardman plant by (a) the failure to shock CO_2 costs and (b) by the use of unreasonably high natural gas prices.

Finding No. 9. PGE failed to consider the potential for higher coal prices in any of its future scenarios.

Finding No. 10. PGE does not appear to have adequately considered the potential costs of complying with new or revised air emissions requirements and the proper disposal and management of coal combustion wastes.

Finding No. 11. PGE has not provided persuasive evidence that the retirement of the Boardman plant before the year 2020 would adversely affect the reliability of the electric grid in Oregon or its ability to provide reliable service to its customers. Instead, PGE limited its assessment of reliability to whether it would need to purchase power from the market and not to whether it would be unable to do so or would, in any way, be unable to provide power to its customers.

Finding No. 12. Fuel diversity is an important consideration. However, PGE has failed to demonstrate that the HHI differences between portfolios presented in the IRP are in any way significant.

Finding No. 13. Despite these flaws and biases, the results of PGE's IRP modeling show that investing $510 million in a scrubber and other environment control equipment for the Boardman plant is not part of a lowest cost, low risk resource plan.

Finding No. 14. The results of PGE's modeling analyses show that by 2020 Boardman will no longer be a baseload generating unit even if $510 million is invested in environmental upgrades.

Finding No. 15. PGE's analyses that purport to show that retirement of the Boardman plant in 2020 would be a lower cost and lower risk option than retirement in an earlier year are biased in favor of the later retirement date.

Findings

Finding No. 1. PGE used unreasonably high natural gas prices in its IRP modeling analyses (both deterministic and stochastic) that biased the analyses against natural gas-fired alternatives and in favor of the continued operation of the Boardman plant

PGE has said that its objective in resource planning to "to identify a robust portfolio that performs better than the alternatives under a wide range of *credible* futures."[1] [Emphasis added] PGE also has acknowledged that "[o]f 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."[2]

Therefore, it is quite unfortunate that, as can be seen in Figure 1, below, PGE has used natural gas prices in its IRP analyses that are simply not 'credible.' Instead, the natural gas prices that PGE used in its IRP are much higher than the future natural gas prices projected by NWPCC, the Oregon PUC staff, and the U.S. Department of Energy's Annual Energy Outlook for 2010 ("AEO 2010"), as well as current NYMEX futures prices.

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1 IRP Addendum, at page 49.
2 Id, at page 101.

Figure 1: Natural Gas Prices Used in IRP Modeling Analyses vs. NWPCC, Oregon PUC Staff, AEO 2010 and NYMEX Futures (Levelized in 2009$)

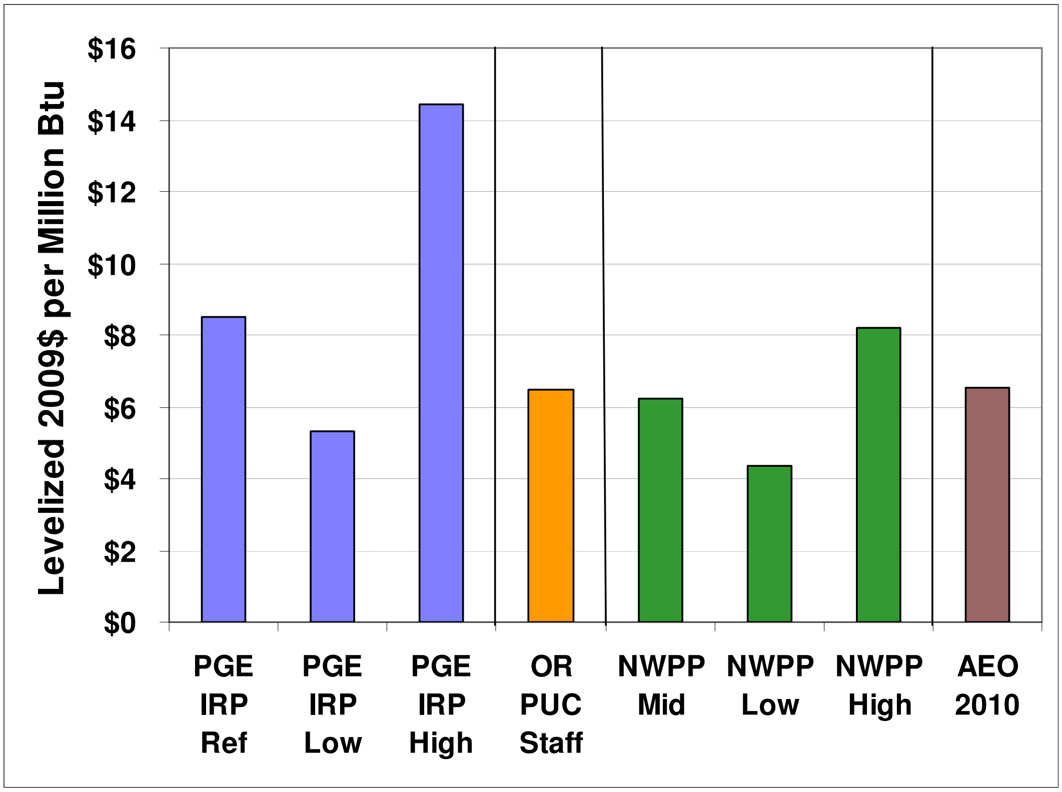

Figure 1 shows that:

- The reference case natural gas prices that PGE used in its IRP analyses are significantly higher than Oregon PUC Staff, NWPP mid and AEO Forecasts and NYMEX futures prices.
- PGE's IRP reference case natural gas prices are actually slightly higher than NWPCC's *high* gas price forecast.
- PGE's IRP high natural gas price forecast is dramatically higher than NWPCC high forecast.
- On a levelized basis, the PGE IRP high gas price forecast is 70 percent higher than the PGE reference case forecast while the NWPCC high gas price forecast is only 32 percent higher than the NWPCC mid forecast.

The following two confidential Figures compare the annual reference case and 'high case' natural gas prices that PGE used in the IRP with the same forecasts from the NWPCC, the Oregon PUC staff, AEO 2010 and current NYMEX futures.

Figure 2: **Annual Natural Gas Prices Used in Reference Case IRP Modeling vs. NWPCC, Oregon PUC Staff, AEO 2010 and NYMEX Futures**

[Confidential. Please See Page 6 of Confidential Version]

Figure 3: Annual Natural Gas Prices Used in 'High Gas Price' IRP Modeling vs. NWPCC, Oregon PUC Staff, AEO 2010 and NYMEX Futures

[Confidential. Please See Page 7 of Confidential Version]

The use of unreasonable natural gas prices artificially raises the cost of each of the portfolios considered in the PGE IRP but has a bigger impact on those portfolios that rely more heavily on natural gas generation. This means that the NPVRR of those portfolios with larger amounts of natural gas generation, e.g., the Boardman retirement portfolios, will be more heavily impacted (i.e., increased) by using unreasonably high natural gas prices than will the NVPRR of those scenarios which assume the continued operation of the Boardman plant through 2040.

The unreasonably high natural gas prices used by PGE in its IRP modeling analyses also distort its risk assessments. This is because two of the 21 futures scenarios in which PGE examined its pre-selected resource portfolios were (1) the 'High Gas' future and (2) the "High CO_2 cost with high natural gas prices and low coal prices."[3] PGE has acknowledged that the ""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."[4] Indeed, the "Boardman through 2014" portfolio is more exposed to gas than the "Boardman through 2020" portfolio because it adds the gas-fired CCCT six years earlier.

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3 IRP Addendum, at pages 29 and 30.
4 Id, at page 101.

Consequently, it is no surprise that the NPVRR of the Boardman through 2014 is the most heavily impacted by the extremely high, and very unreasonable, high gas price forecast shown in Figures 1 and 3, above, that PGE uses in its IRP modeling. As a result, the Boardman through 2014 portfolio performs worst in the two "high gas price" futures scenarios.

In this way, the extremely high natural gas prices distort the metrics PGE uses to measure risk in its deterministic modeling analyses: the "Average Cost of Four Worst Futures" and the "Average Cost of Four Worst Futures Less the Cost of Reference Case." By using unreasonably high natural gas prices in these futures, PGE increases the apparent riskiness of the Boardman through 2014 portfolio. For this reason, the risk assessment (and related portfolio scoring based on these metrics) presented in the IRP Addendum does not provide any insight into the actual relative economic risk of retiring the Boardman plant in 2014 or, indeed, any year prior to 2040.

Although the IRP does discuss the recently changed circumstances regarding natural gas, it doesn't seem to have considered those changed circumstances in the natural gas prices it used in its IRP analyses. This is quite unlike other utilities, such as the Entergy Corporation, and an increasing number of gas and electric industry sources which consider the changed circumstances as a structural change in the natural gas market.

This structural change has two important impacts on the resource planning for companies like PGE. First, as a result of the existing and expected supply glut, current and projected prices of natural gas have been significantly reduced. At the same time, the dramatically larger domestic supplies of natural gas should be able to accommodate any increased demands from any fuel switching due to the relative economics of gas-fired vs. coal—fired generation or federal regulation of greenhouse gas emissions without causing significant increases in natural gas prices.

The structural change in the natural gas markets already has had a significant impact on utilities' resource planning. For example, in early April of last year, Entergy Louisiana informed the Louisiana Public Service Commission of its intent to defer (and perhaps cancel) the proposed retirement of an existing gas-fired power plant and its replacement by a new coal-fired unit. Entergy explained that it no longer believed that a new coal plant would provide economic benefits for its customers due to its current expectation that future gas prices would be much lower than previously anticipated:

> Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently – and for

> the first time – projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource.[5]
>
> 4. Recent Natural Gas Developments
>
> Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $131.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.
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> * * * *
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> However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. **The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run….**
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> * * * *
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> Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods…[6] [Emphasis added]

Entergy's conclusion that there has been a seismic shift in the domestic natural gas industry was confirmed in early June of 2009 by the release of a report by the American

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5 *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009, at pages 6-8.

6 Id, at pages 17, 18 and 22.

Gas Association and an independent organization of natural gas experts known as the Potential Gas Committee, the authority on gas supplies. This report concluded that the natural gas reserves in the United States are 35 percent higher than previously believed. The new estimates show "an exceptionally strong and optimistic gas supply picture for the nation," according to a summary of the report.[7]

A Wall Street Journal Market Watch article titled "U.S. Gas Fields From Bust to Boom" similarly reported that huge new gas fields have been found in Louisiana, Texas, Arkansas and Pennsylvania, and cited one industry-backed study as estimating that the U.S. now has enough natural gas to satisfy nearly 100 years of current natural gas-demand.[8] It further noted that

> Just three years ago, the conventional wisdom was that U.S. natural-gas production was facing permanent decline. U.S. policymakers were resigned to the idea that the country would have to rely more on foreign imports to supply the fuel that heats half of American homes, generates one-fifth of the nation's electricity, and is a key component in plastics, chemicals and fertilizer.
>
> But new technologies and a drilling boom have helped production rise 11% in the past two years. Now there's a glut, which has driven prices down to a six-year low and prompted producers to temporarily cut back drilling and search for new demand.[9]

There is now wide agreement among gas industry experts that this is not a short-term phenomenon but is a long-term structural change in the natural gas market. PGE should reflect this structural change, and the expectation of lower long-term natural gas prices, in its IRP analyses. It has not done so.

It is our understanding that the Sierra Club does not oppose the development of shale gas resources using fracturing technologies as long as production is governed by a robust and effective regulatory structure. According to Sierra Club's policy; all gas should be produced using rigorous best management practices to limit environmental damage.[10]

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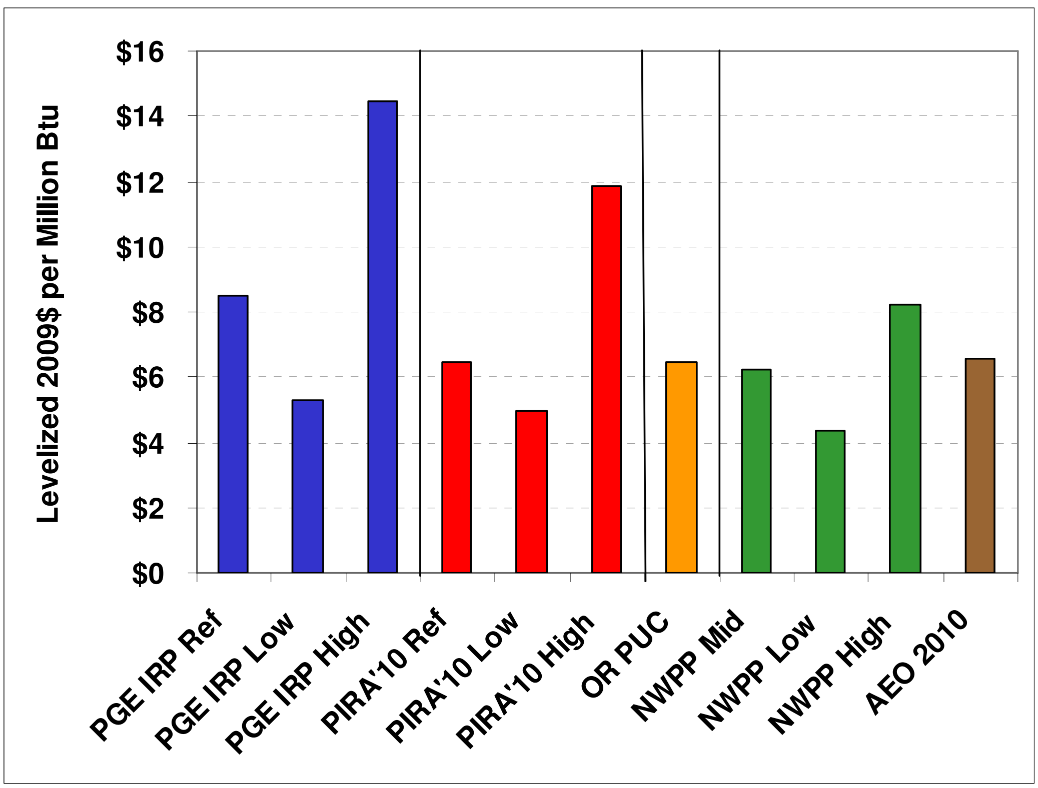
7 *Estimate Places Natural Gas Reserves 35 percent Higher*, New York Times, June 9, 2009.
8 Available at http://online.wsj.com/article/SB124104598912705857.html.
9 Id.
10 The Sierra Club's shale gas policy is available at http://www.sierraclub.org/policy/conservation/NaturalGasFracturing.pdf.

Finding No. 2. PIRA has significantly reduced its projected natural gas prices from the forecasts used in the PGE IRP analyses. These new forecasts confirm our conclusion that the gas prices used in the IRP analyses were unreasonably high.

PGE's May 7, 2010 response to PEAC Data Request Question No. 77 provided PIRA's new April 2010 reference natural gas price forecast and its new February 2010 high and low gas price forecasts. As can be seen in Figure 4, below, on a levelized basis these forecasts are substantially lower than the gas price forecasts that PGE used in the IRP analyses. The new PIRA forecasts also appear to be much more consistent with the natural gas price forecasts from NWPCC, AEO 2010 and the Oregon PUC staff.

Figure 4: 2010 PIRA Natural Gas Price Forecasts vs. The Gas Prices Used in IRP Modeling Analyses and the NWPCC, Oregon PUC Staff, AEO 2010 and NYMEX Futures Prices (Levelized in 2009$)



Confidential Figure 5 then compares PIRA's new annual reference case natural gas price forecasts with the other reference case forecasts included in Figure 2 above.

Figure 5: 2010 PIRA Natural Gas Price Forecasts vs. The Gas Prices Used in IRP Modeling Analyses and the NWPCC, Oregon PUC Staff, AEO 2010 and NYMEX Futures Prices (2009$)

[Confidential. Please See Page 12 of Confidential Version]

These new gas-price forecasts confirm our finding that the natural gas prices that PGE used in its IRP analyses were much too high and that the results of those analyses, therefore, are biased against natural gas-fired generation and in favor of the continued operation of the Boardman plant.

For this reason, alone, little or no weight should be given to the claims and modeling results presented in the November 2009 Final IRP and the IRP Addendum filed by PGE in April 2010 regarding (a) the reasonableness of making the emissions controls investments needed operate the Boardman plant through 2040 and (b) the better economics of the Boardman through 2020 portfolio over portfolios that would retire the Boardman plant in earlier years.

Finding No. 3. PGE has not analyzed whether adding a new combined cycle natural gas-fired unit would be the lowest cost option if Boardman were retired at any time between 2014 and 2020.

PGE has assumed in the early Boardman retirement portfolios that the plant would be replaced by an equivalent natural gas-fired combined cycle generating unit. However, the Company made no attempt to determine whether such a replacement was a "least-cost replacement of Boardman."[11] Instead, the Company assumed a new gas-fired unit would be built in place of Boardman because it "is a replacement of one non-intermittent base load resource by another."

Thus, the Company is unable to say that it wouldn't be less expensive to replace Boardman with some combination of a mid- to long-term power purchase agreement ("PPA"), additional energy efficiency, additional renewable resources plus, perhaps, some new gas-fired capacity at some point in time. This is a critical flaw in the IRP modeling process and, as a result, PGE may be overlooking alternatives to Boardman that are better from economic, environmental and reliability perspectives than building a new natural gas-fired central station power plant.

In fact, PGE did not optimize any of the portfolios it considered in the IRP. Instead of allowing the Aurora model to identify lowest cost portfolios of new gas-fired units, new renewable resources and new amounts of cost-effective energy efficiency, PGE pre-selected the supply-side and demand-side resources that would be added in each portfolio. The Company also failed to modify or adjust its portfolios in light of its initial modeling results. Thus, the Company really can't say that there are not lower cost, lower risk portfolios than the 16 it has examined.

Finding No. 4. PGE has not adequately considered the availability of a substantial amount of under-utilized gas-fired combined cycle and gas turbine capacity in and around the state of Oregon that could provide much, if not all, of the replacement energy if the Boardman plant were retired.

The IRP explains that all portfolios were limited to 300 MW of market capacity purchases each year and to 100 MWa of short- and mid-term energy purchases.[12] However, it appears that PGE only considered a multi-year PPA as a supply side alternative in four portfolios: the Bridge to IGCC in Wyoming portfolio, the Bridge to Nuclear in Idaho portfolio, the Boardman through 2011 portfolio and the Boardman through 2020 portfolio. The potential for a PPA was not considered in the Boardman through 2014 or the Boardman through 2017 portfolios. This is a significant flaw given that there appears to be substantial available gas-fired capacity and energy in Oregon and the Northwest to form a medium-term to long-term PPA (4-5 years or longer) that could, if necessary, replace the power that would be generated at Boardman for at least the

11 PGE Response to PEAC Data Request Questions Nos. 65 and 66.
12 IRP Addendum, at page 19.

medium term (4-5 years) while longer term options such as additional energy efficiency and renewable resources develop and, perhaps, a new combined cycle unit is built.

For example, in its Opening Comments in this proceeding, the Northwest and Intermountain Power Producers Coalition ("NIPPC") noted the following:

> NIPPC understands that PGE's preferred plan for the future of the Boardman plant is still under development, so NIPPC defers a detailed review of PGE's arguments regarding future operation of the Boardman plant until PGE's plan is better defined and supported. Nevertheless, NIPPC feels compelled to point out within the context of the Commission's review of the utility's IRP, that PGE's recommendation to continue operation of the Boardman plant at least over the near to mid-term due to claims of insufficient sources of replacement power does not match market realities. The Northwest Power & Conservation Council identified in its Fourth Power Plan that substantial un-contracted merchant plant capacity remains uncommitted and is available for contract under long-term PPA. In 2010, a conservative estimate found on the order of 3,000 MW currently exists in the region and is available to meet capacity shortfalls from the closure of the Boardman plant.[13]

Moreover, information from the NWPCC reveals that there is substantial under-utilized gas-fired combined cycle capacity in the region.

Table 1: Pacific Northwest Combined Cycle Capacity Factors in 2007 and 2008.[14]

Name	Technology	Primary Fuel	Installed Capacity (MW)	Initial Service Year	State	2007 Capacity Factor	2008 Capacity Factor
Beaver 1 - 7	CC	NG	586.2	1974	OR	7.10%	2.83%
Big Hanaford CC1A-1E	CC	NG	322.0	2002	WA	12.55%	11.07%
Chehalis Generating Facility	CC	NG	593.3	2003	WA	36.32%	40.96%
Coyote Springs 1	CCCG	NG	266.4	1995	OR	61.64%	64.61%
Coyote Springs 2	CC	NG	287.0	2003	OR	64.53%	67.47%
Encogen 1-4	CCCG	NG	176.4	1993	WA	11.73%	6.32%
Frederickson Power 1	CC	NG	318.3	2002	WA	32.27%	39.27%
Goldendale CC 1A & 1B	CC	NG	280.3	2004	WA	28.29%	55.04%
Grays Harbor Energy Facility (Satsop)	CC	NG	650.0	2008	WA	0.00%	14.37%
Hermiston Generating Project CC2A & 2B	CCCG	NG	234.5	1996	OR	55.47%	59.19%
Hermiston Power Project	CCCG	NG	689.4	2002	OR	50.97%	61.60%
Klamath Cogeneration Project	CCCG	NG	501.5	2001	OR	55.41%	69.10%
Lancaster (Rathdrum Generating Station)	CC	NG	270.0	2001	ID	53.93%	57.90%
March Point 1 - 4	CCCG	NG	167.0	1991	WA	69.32%	69.91%
Mint Farm	CC	NG	319.0	2008	WA	0.00%	25.71%
Port Westward CC1A & 1B	CC	NG	399.0	2007	OR	49.27%	81.08%
River Road Generating Plant	CC	NG	248.0	1997	WA	70.04%	74.40%
Sumas Cogeneration Station	CCCG	NG	125.5	1993	WA	20.64%	19.67%
Tenaska Washington Partners Cogeneratio	CCCG	NG	253.4	1994	WA	32.52%	27.53%

13 *Opening Comments of the Northwest and Intermountain Power Producers Coalition*, February 2, 2010, at pages 17 and 18.

14 NWPCC File name *Existing Projects 030210.xls*.

PGE disputes the availability and deliverability of power through a PPA in the November 2009 Final IRP.[15] However, the Company does not appear to have conducted any detailed analyses to support its claims:

- In its response to PEAC Data Request Question No. 053, PGE acknowledged that its "position regarding the amount of uncommitted merchant generation in the Pacific Northwest, as noted on page 48 of the IRP, is therefore not based on formal analysis or studies."
- In its response to PEAC Data Request Question No. 071, PGE noted that it "has not performed an assessment of potential power purchase agreements for energy or capacity for delivery during the period of July 1, 2014 through December 31, 2020. Doing so would require speculation as to both supply availability and price in the absence of conducting a market solicitation or competitive bidding process. We believe this would not be a sound basis for performing IRP analysis."
- In its response to PEAC Data Request Question No. 101, PGE was unable to provide any assessments or analyses of system constraints that would affect the ability to build a replacement unit or buy power from a replacement source in the event that Boardman is retired at some time between January 1, 2014 and December 31, 2020.

PGE also has acknowledged that it has not studied the impacts of retiring the Boardman plant on the transmission grid.[16]

Finding No. 5. PGE overstates its need for the capacity and energy from the Boardman plant through the use of high load forecasts and by understating the potential for energy efficiency.

PGE assumed high energy and peak load growth through 2030 in its IRP modeling analyses. For example, as explained in the IRP Addendum, PGE used a reference case energy load growth rate, including embedded energy efficiency, of 1.9 percent per year between 2010 and 2030.[17] PGE also examined futures with higher (2.7 percent per year) and lower load growth (1.2 percent per year).[18]

However, the energy and peak load growth rates that PGE used in the IRP are higher than both PGE's actual energy growth between 1998 and 2008 and the current forecasts of the Northwest Power and Conservation Council for Oregon.

In fact, as shown in Table 2, below, information in the *2008 Oregon Utility Statistics* published by the Commission, reports that PGE's total energy loads grew from 19,258,992 MWh in 1999 to 19,992,632 MWh in 2008. This represented a total growth in

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15 At page 48
16 PGE's Response to PEAC Data Request Question No. 103.
17 IRP Addendum, at page 28.
18 IRP Addendum, at page 30.

energy load of less than four percent during the entire nine year period or an average annual growth rate of only 0.4 percent per year. Interestingly, PGE's average number of customers, excluding ESS customers, grew by 14 percent during this same nine year period, from 714,000 to 811,000. Average usage per customer declined.

Table 2: PGE Historical Sales and Peak Loads from 1999 through 2008

Portland General Electric Company
TEN-YEAR SUMMARY
SELECTED STATISTICS

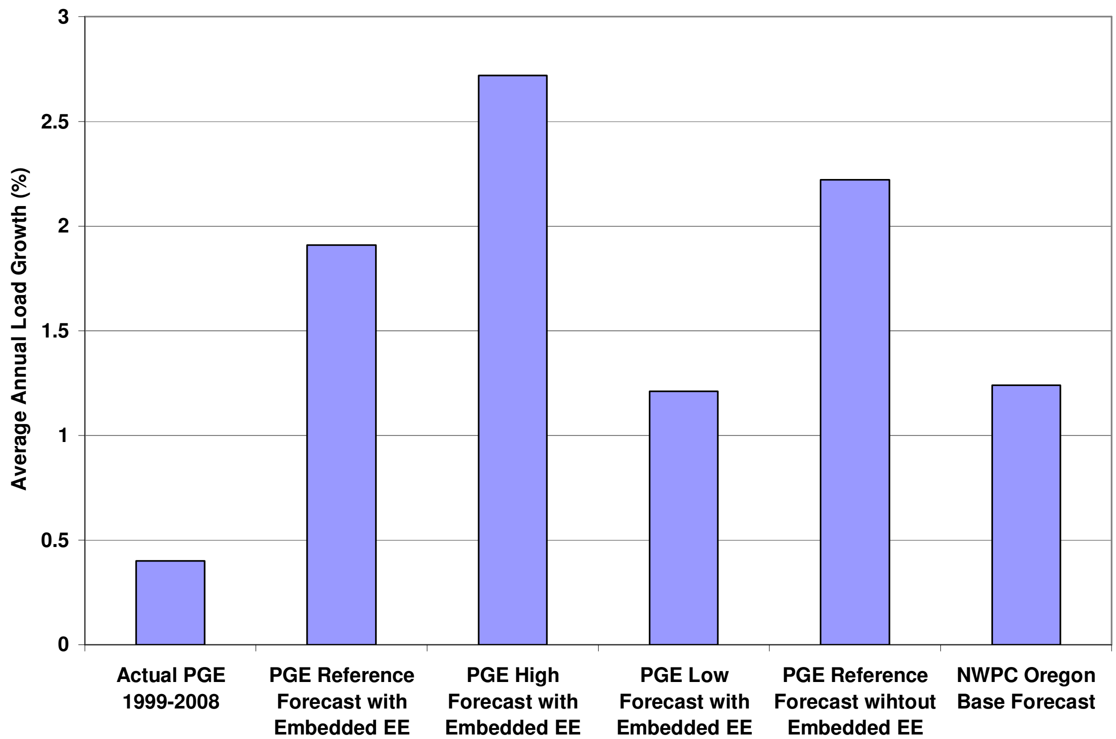
	Oregon Total[A]					Residential Averages in Oregon			
				Average[D]				Per Customer	
	Revenue From Retail Energy Customers	Energy Sold to Retail Customers (MWh)[B]	Delivery to ESS Customers (MWh)[B]	Number of Customers	Revenue Per kWh (Cents)	Number of Customers	Revenue Per kWh (Cents)	Revenue	kWh
1999	$973,326,617	19,258,992	NA	714,130	5.05	627,396	5.90	$697	11,802
2000	$1,038,204,376	19,872,544	NA	726,039	5.22	637,331	6.02	$702	11,663
2001	$1,096,155,658	19,040,188	NA	733,058	5.76	643,596	6.59	$725	11,001
2002	$1,384,322,786	18,771,884	0	741,949	7.37	649,674	8.05	$874	10,864
2003	$1,283,136,445	18,425,854	0	750,496	6.96	658,232	7.82	$844	10,785
2004	$1,262,880,182 [C]	17,764,138	775,878	762,336	7.11 [E]	668,830	8.05	$875	10,870
2005	$1,264,877,648 [C]	17,540,047	1,213,906	775,533	7.21 [E]	680,093	8.10	$872	10,768
2006	$1,361,008,240 [C]	18,432,527	998,574	788,831	7.38 [E]	691,931	8.29	$907	10,944
2007	$1,439,248,223 [C]	17,461,742	2,164,687	800,587	8.24 [E]	701,952	9.31	$1,020	10,953
2008	$1,483,317,814	17,575,806	2,417,316	811,315	8.44	710,991	9.62	$1,066	11,080

Despite this recent history, PGE assumed in its IRP analyses that its future energy load growth rate will increase significantly from the 0.4 percent average annual rate the Company actually experienced between 1999 and 2008 to an average 1.9 percent increase per year beginning in 2010. However, PGE has not provided much evidence to support such a change.

PGE also claims that its energy growth forecasts are consistent with the NWPCC's Draft Sixth Plan forecasts (now adopted as the Sixth Plan Forecasts). [19] However, that claim does not appear to be accurate, as shown in Figure 6, below.

[19] November 2009 Final IRP, at page 37.

Figure 6: PGE Assumed Load Growth vs. NWPCC Oregon Forecast[20]



Thus, PGE's Reference and High Forecasts with Embedded EE and its Reference Forecast without Embedded EE are all significantly higher than the NWPC Oregon Base Forecast. Only the PGE Low Forecast with Embedded EE is comparable to the NWPCC Oregon Forecast. Consequently, it is extremely hard to see how PGE's energy forecasts are 'consistent" with those of the NWPCC.

NWPCC also anticipates that energy efficiency could have a much greater impact on load growth than PGE does. In fact, NWPCC's Sixth Plan assumes that energy efficiency could reduce energy load growth in the State of Oregon from 1.24 percent per year between 2010 and 2030 to an average of only 0.34 percent per year, a reduction of nearly 73 percent. PGE, on the other hand, assumes that energy efficiency will only reduce its load growth by a cumulative 28 percent through 2030.[21]

[20] The information in this Figure is taken from Tables 3-1 and 3-2 on pages 36 and 37 of the November 2009 Final IRP.

[21] See Table …on page … of the IRP.

Finding No. 6. PGE has significantly reduced its long term energy and peak load forecasts in December 2009.

PGE's May 5, 2010 response to PEAC Data Request Question No. 78 provided the Company's December 2009 energy and peak load forecasts. As shown in Figures 7.a. and 7.b., below, the new December 2009 forecasts are substantially below the March 2009 load forecasts that PGE used in its IRP modeling.

Figure 7.a: PGE March 2009 Energy Forecast Used in IRP vs. Company's December 2009 Forecast

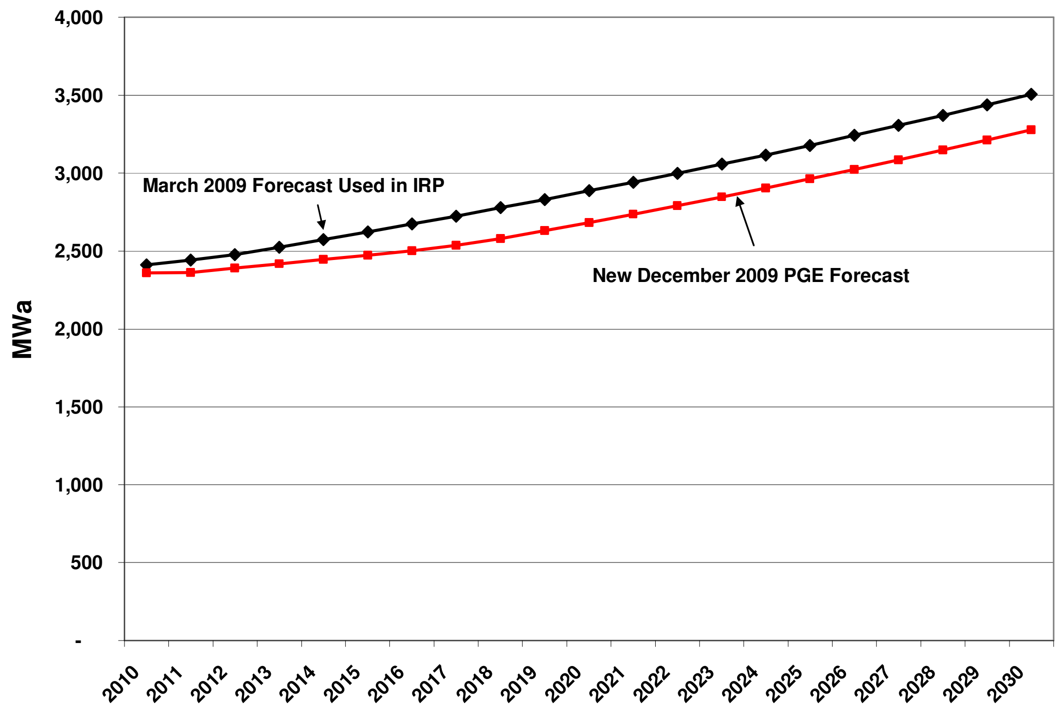
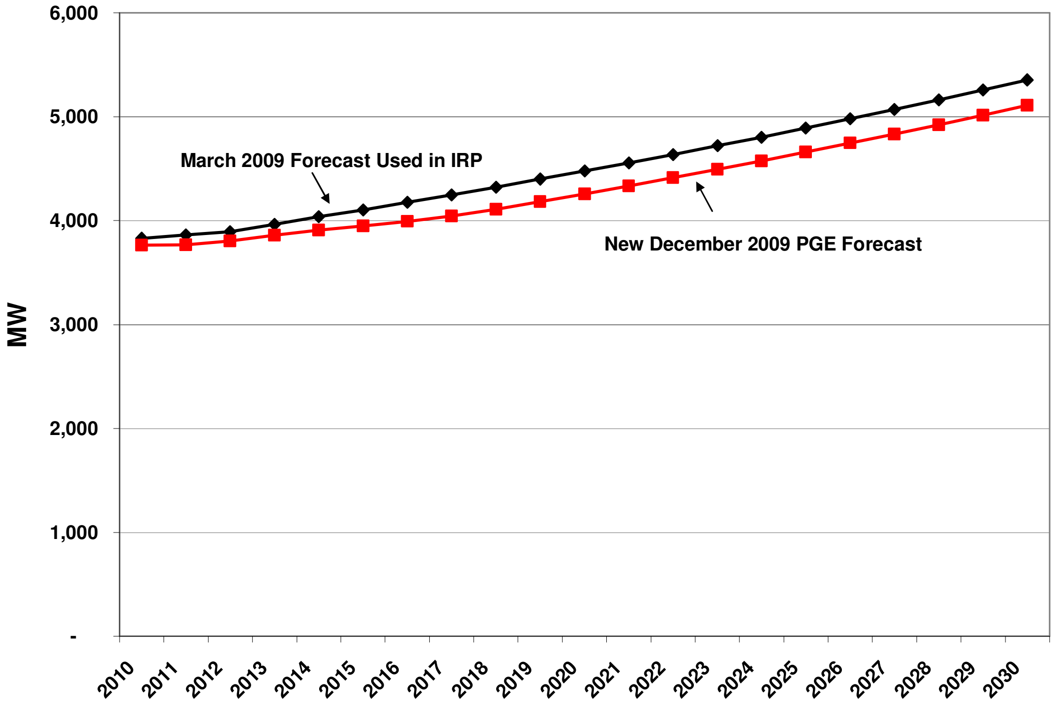


Figure 7.b.: PGE March 2009 Peak Load Forecast Used in IRP vs. Company's December 2009 Forecast



Even though PGE has only slightly reduced its projected long-term 2010-2030 average energy and peak load growth rates,[22] the annual reductions are significant as shown in Figures 8.a. and 8.b. below, and reduce PGE's need for the capacity and energy from the Boardman plant.

[22] PGE reduced its 2010-2030 long-term energy load growth rates from an average 1.9 percent per year in the March 2009 forecast to 1.7 percent per year in December 2009. The Company similarly reduced its long-term peak load growth rate from 1.7 percent in the March 2009 forecast to 1.5 percent in the December 2009 forecast. These remain substantially higher than the Company's historical growth between 1999 and 2009 and the load growth projected by NWPCC for Oregon.

Figure 8.a.: Annual Reductions in PGE Energy Load Forecasts between March 2009 Forecast Used in IRP and December 2009 Forecast

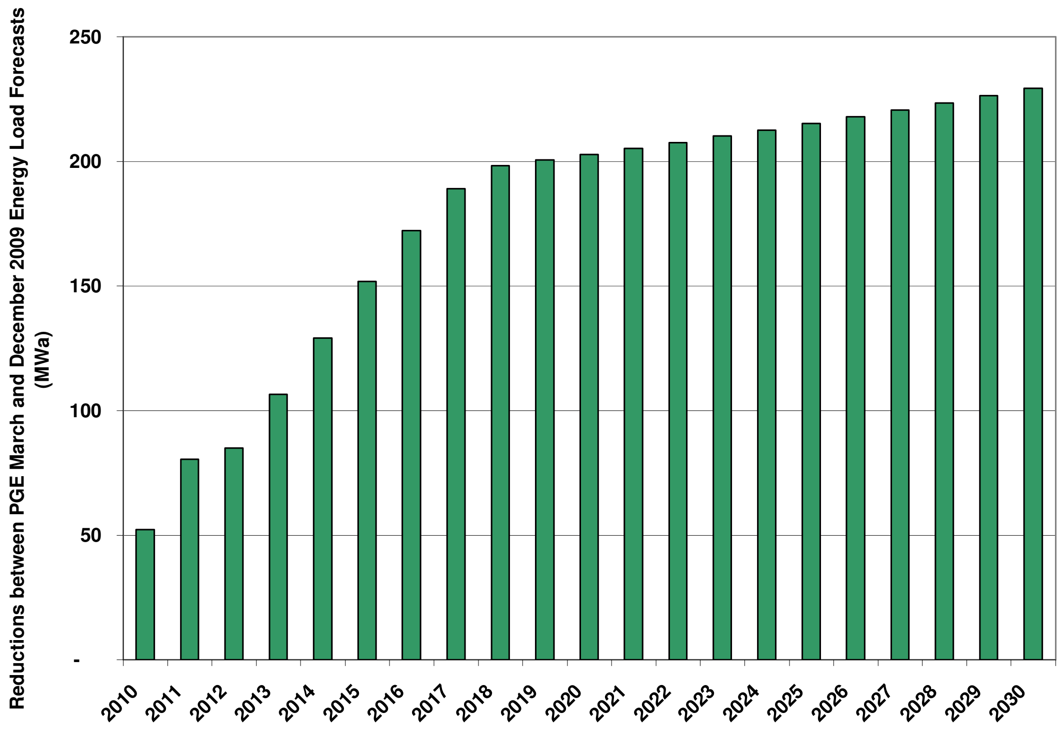
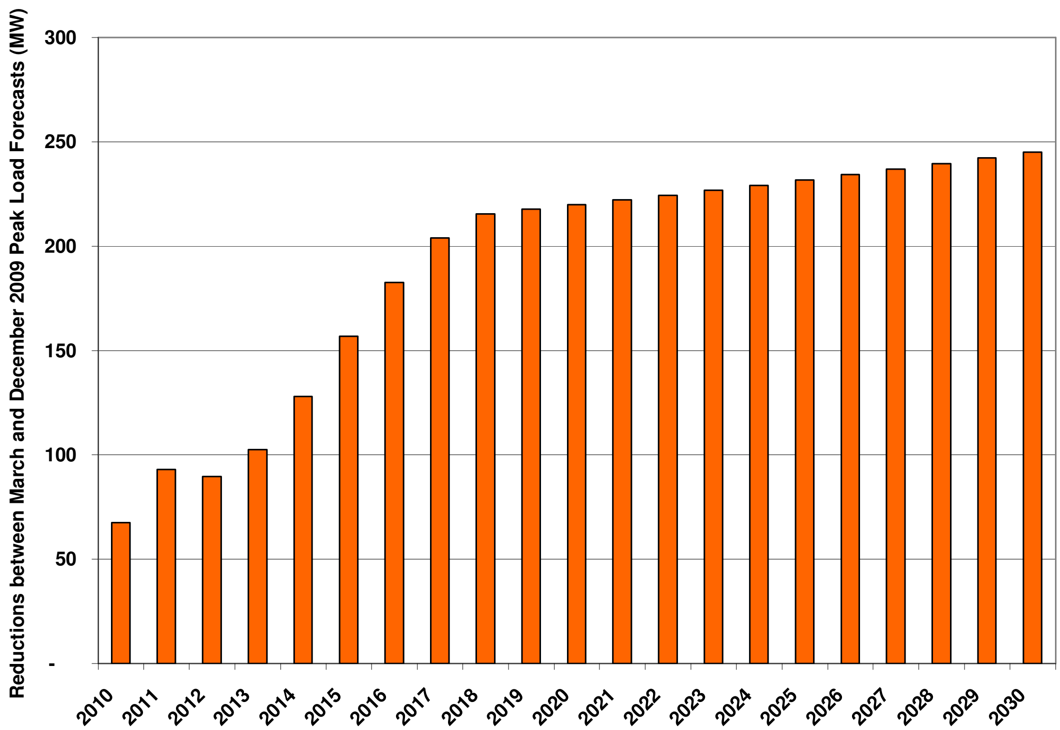


Figure 8.b.: Annual Reductions in PGE Peak Load Forecasts between March 2009 Forecast Used in IRP and December 2009 Forecast



Consequently, PGE has reduced the energy forecast used in its reference case IRP analyses by between 5.8 percent in 2015 to 6.5 percent in 2030. PGE similarly has reduced the peak load forecast used in its IRP analyses by 3.8 percent in 2015 increasing to 4.6 percent in 2030. It is reasonable to expect that these reductions in energy and peak loads substantially affect PGE's need for the energy and capacity from the Boardman plant. However, we have not seen any evidence that PGE has rerun its IRP analyses in light of its December 2009 forecasts.

PGE's response to PEAC Data Request No. 78 says that some of the difference between these two forecasts is due to the inclusion of Schedule 109 Incremental Energy Efficiency Funding (authorized by Senate Bill 838) and that the effect of these incremental EE savings was incorporated in the IRP. However, it is unclear how much of the difference between the March 2009 and December 2009 energy and peak load forecasts these incremental EE savings actually represent. In any event, it still appears, though, that PGE's December 2009 energy and peak load forecasts are significantly lower than the earlier forecasts used in the IRP modeling.

Finding No. 7. **The results of PGE's IRP modeling analyses show that if PGE continues to operate the Boardman plant past 2020, its annual CO_2 emissions will be significantly higher in 2030 than they were in 2007. Even if PGE retires the Boardman within the next ten years, its annual CO_2 emissions in 2030 still will be higher than they were in 2007. Therefore, PGE must start to aggressively plan to achieve actual reductions in its CO_2 emissions rather than assuming, as it does in its IRP, that it will be able to continue emitting the same or higher levels of CO_2 by purchasing emissions allowances. Making large investments in the Boardman plant and continuing to operate the plant through 2040 would be a step in the wrong direction.**

PGE is to be commended for examining a fairly wide range of CO_2 prices in its IRP modeling analyses. However, as shown in Figures 9 and 10, below, the results of those analyses show that the Company's annual CO_2 emissions in both the Diversified Thermal with Green (i.e., Boardman through 2040) and the Boardman through 2014 portfolios will be significantly higher in 2030 than they were in 2007 – although the annual emissions in the Boardman through 2014 portfolio would be substantially lower than in the Diversified Thermal with Green portfolio.

Figure 9: **Annual PGE CO_2 Emissions in Diversified Thermal with Green and Boardman through 2014 Portfolios with Reference Case CO_2 Prices**

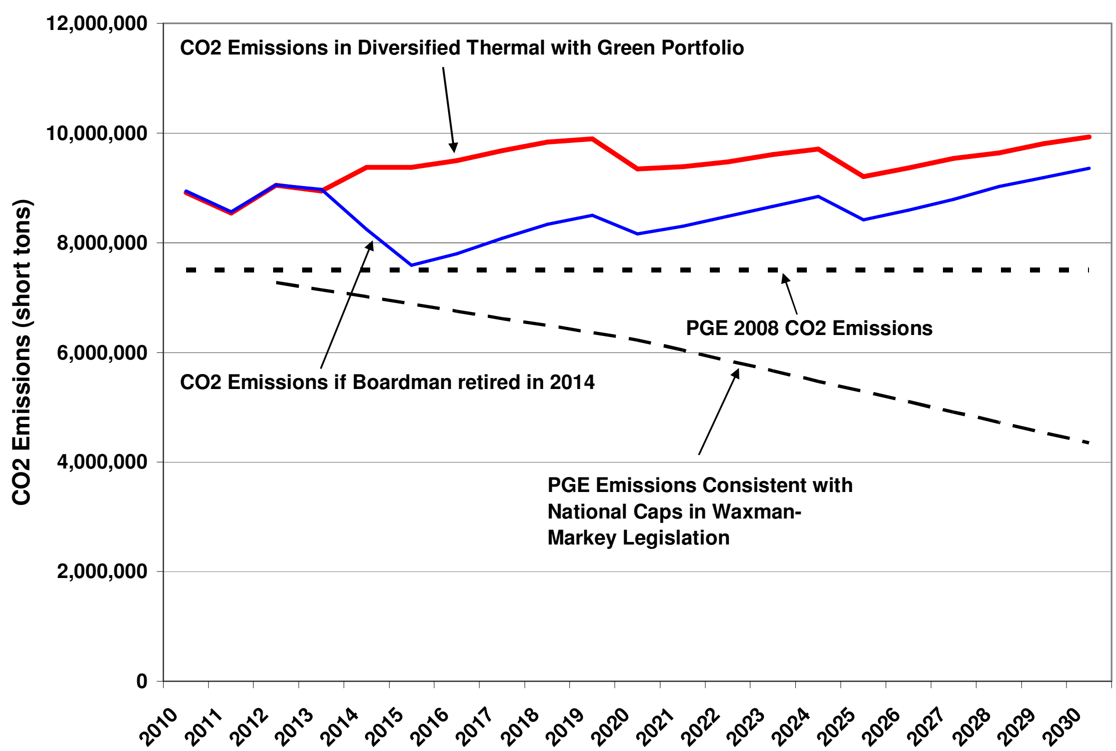


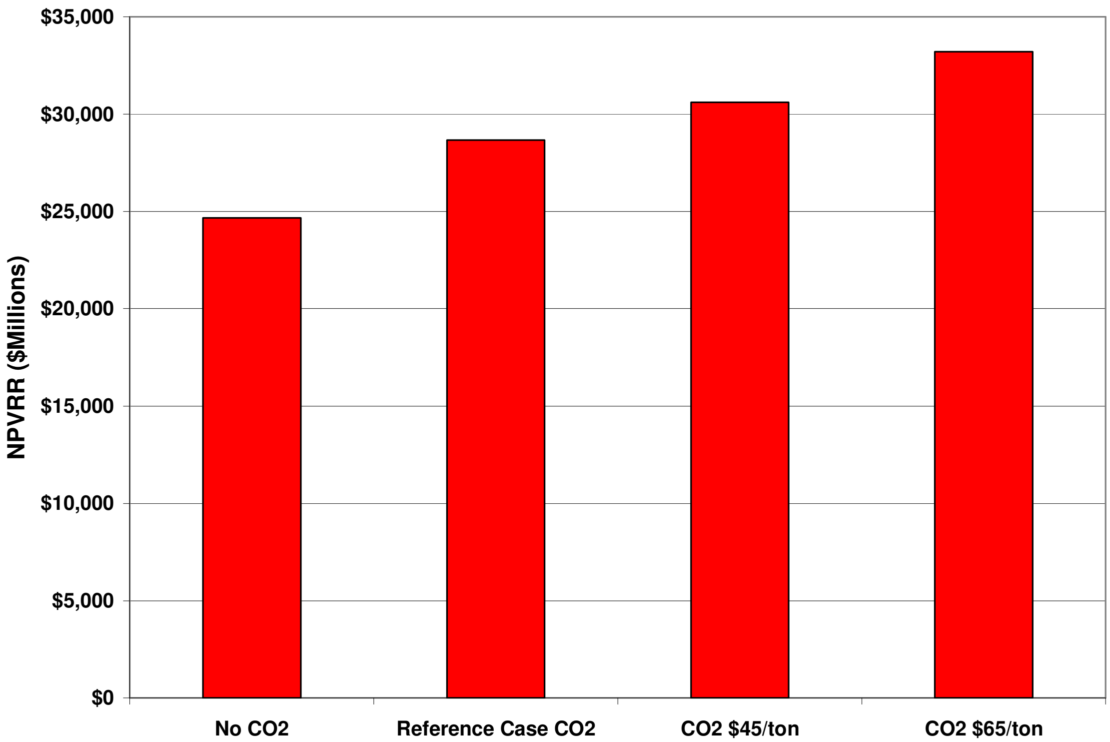
Figure 10: Annual PGE CO_2 Emissions in Diversified Thermal with Green and Boardman through 2014 Portfolios with High CO_2 Prices ($65/ton) [Confidential. Please See Page 23 of Confidential Version]

Unfortunately, PGE has not provided the annual CO_2 emissions for its Boardman through 2020 portfolio. However, Figure 11-16 in the IRP Addendum similarly shows that PGE's annual CO_2 emissions in the Boardman through 2020 portfolio with reference case CO_2 prices also would be approximately 10% to 15% higher in 2030 than they were in 2007. It is important to remember that the CO_2 emissions in Figures 9 and 10 are for PGE's reference case and high CO_2 price scenarios. The Company's annual CO_2 emissions in these portfolios can be expected to be even higher in the scenarios with the no CO_2 or low CO_2 prices.

A comprehensive system for federal regulation of CO_2 and other greenhouse gases is inevitable. It is generally expected that this federal regulation will require steep reductions in greenhouse gas emissions. However, as shown in Figures 9 and 10, PGE's IRP analyses show that its annual CO_2 emissions will increase over time, not decrease. Consequently, PGE's projected future CO_2 emissions would be in conflict with evolving state, regional and national climate policies.

Moreover, ratepayers will face significant financial risk associated with a decision to lock in increasing CO2 emissions for the coming decades at a time when those emissions will be costly. This financial risk is quite substantial as is illustrated in Figure 11, below, which compares the NPVRR of PGE's Diversified Thermal with Green portfolio in the No CO_2 scenario with its NPVRR in the reference and high CO_2 price scenarios.

Figure 11: NPVRR of Diversified Thermal with Green Portfolio in PGE CO_2 Price Scenarios



Thus, the NPVRR of the Diversified Thermal with Green portfolio could increase by as much as 35 percent, or approximately $8.5 billion, depending on how CO_2 prices actually evolve over time.

Retiring the Boardman plant in the near future will not, on its own, bring PGE's projected greenhouse gas emissions into compliance with expected federal limits but would be a major step in the right direction. Continuing to operate the plant through 2040 would be a major step in the wrong direction and would make it much harder to achieve actual reductions in PGE's CO_2 emissions.

Finding No. 8. The results of PGE's stochastic analyses are distorted in favor of the continued operation of the Boardman plant by (a) the failure to shock CO_2 costs and (b) by the use of unreasonably high natural gas prices.

The Commission should give very little weight to the stochastic analyses presented by PGE in the IRP for three reasons.

First, I agree with PGE's assessment of the greater importance of deterministic scenario analyses in resource planning:

> We have found that the most substantial risks in connection with making future resource choices are those associated with large fundamental or structural shifts – the types of risks best described through scenario analysis. As a result, we believe that scenario analysis should be given the primary emphasis in our overall portfolio risk evaluation.[23]

Second, it appears from Table 11A-1 in the IRP Addendum that PGE used even higher average natural gas prices in the stochastic analyses than it did in its deterministic reference case.[24] Given this high range of natural gas prices, the Tail Var results in Figures 11A-8 through 11A-10 in the IRP Addendum are not surprising given that the Boardman retirement scenarios have a greater dependence on natural gas. This greater dependence on gas is the direct result of PGE's arbitrary assumption that Boardman would be replaced by a natural gas combined cycle unit.

Third, PGE ignores CO_2 prices in its stochastic analyses. This is a critical omission that biases the results in favor of the portfolios with continued operation of the Boardman plant because CO_2 prices are most important for the coal alternative as coal is the most carbon-intensive fuel.

Indeed, it is remarkable that PGE failed to shock CO_2 costs in its stochastic analyses because it did shock natural gas prices and load growth rates even though ranges for both of these input assumptions also were considered in PGE's deterministic scenario analyses. In fact, it is reasonable to expect that there may be great uncertainty and variations in CO_2 emissions allowance prices in a cap-and-trade regime, which appears more likely to be adopted than a flat tax. For example, the prices of auctioned CO_2 emissions allowances are likely to change from one period to the next based on variations in the supply and demand for the allowances. It would seem that such changes would be just as important to consider in stochastic analyses as the potential uncertainty and potential variability in future natural gas prices and load growth. However, PGE has failed to do so.

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23 IRP Addendum, at pages 38 and 39.
24 Id, at page 60.

Finding No. 9. PGE failed to consider the potential for higher coal prices in any of its future scenarios.

Figure 5-2 at page 86 in the IRP presents a range of Reference, High and Low coal prices. However, PGE did not model any futures scenarios with the high coal prices referenced in this Figure although it did model a future scenario with low coal prices combined with High CO_2 prices and high gas prices. This failure to model high coal price scenarios is particularly unreasonable given PGE's acknowledgment that "market conditions [regarding coal] are not static and there is currently uncertainty around a number of key factors."[25] According to PGE, these uncertainties included the following:

- Investment in rail infrastructure, from terminals to equipment, could be slower than expected.
- Transportation capacity (rail and locomotives), and the availability of train crews as the workforce ages, can also impact the rail rates faced by shippers.
- Railroads could place more emphasis on growth of inter-model traffic, decreasing available cars and track capacity for coal shipments.
- Volatility in the price of diesel, which is a significant cost to rail rtes and the cost of mining.
- The impact of greenhouse gas legislation and any carbon legislation will have a significant impact on the coal industry and will be a key driver for the demand for the coal.
- The commercial viability of carbon capture and sequestration technologies, which will also have an impact on the long term demand and price of coal.
- Global demand, particularly the impact of economic development in China, India and other Southeast Asian countries, could increase demand for Eastern coal.
- Additional Eastern utilities could switch to PRB coal (due to the relative price advantage of PRB coal), even after plant retrofits.
- Producer discipline to respond to changes in demand for coal and shippers' inventory levels in the near term.[26]

In fact, each of the factors cited by PGE is likely to impact coal demand and prices. In addition, there are broader market factors that also are likely to impact coal demand prices.

For example, a *Market Commentary* in the Coal and Energy Price Report noted a number of factors which may increase the demand for and price of PRB coal: 1) future demand in

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[25] Id, at page 89.
[26] Id.

the region would create new mines with less favorable stripping ratios, higher production costs and rising coal prices; 2) new safety policies stemming from mining catastrophes in Central Appalachia would likely extend to the PRB region, and, 3) production and other factors have made it clear that the United States was not a cheap source of coal anymore and for the foreseeable future.[27]

Indeed, a considerable body of evidence indicates that future United States coal markets will not be like past coal markets and that coal commodity prices may be considerably higher. Currently, prices of PRB coal are rising after a decline from historic highs experienced in late 2008. In the short term (the next twelve months), gradual increases can be expected. For the medium and longer term, U.S. coal markets will no longer be a reliable supply of low cost fuel. Instead of being an anomaly, price run-ups that occurred in 2008 may be harbingers of how markets will perform in the future. For example, despite the current recession and relatively low recent prices of coal across the country, industry analysts and market data are suggesting that the price of PRB coal will rise between 2010 and 2012 by approximately 40 percent, and potentially higher.[28]

Evidence also suggests that after 2012 the prices for PRB coal will rise significantly due to new cost pressures as mining becomes more complex and expensive and as large coal producers cultivate a worldwide base of users. Domestically, coal producers will use PRB's low price to capture a larger portion of the energy market (new plants, retrofits and carbon capture projects). Further success with this strategy will place additional upward pressure on prices and hasten the depletion of PRB reserves.

Future PRB coal supplies come with heightened risks. Recent indications from the United States Geological Survey (USGS) and industry leaders have raised red flag warnings about long term supply sufficiency of economically recoverable coal in the Powder River Basin. These price pressures are structural in nature and will redefine the nation's coal markets going forward. The new market environment will create a much higher floor price for PRB coal, one that is less responsive to the normal patterns of domestic business cycles. This will further erode coal's competitive edge with other power generation fuels in the United States.

One study, conducted by the United States Geological Society (USGS), released in 2008 raised a fundamental question about the size and quality of economically recoverable coal

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27 Energy Publishing, Inc. *Market Commentary,* Coal and Energy Price Report, Volume 12, No 88, May 10, 2010.

28 Peabody Energy, Forward Looking Statement, February 18, 2010 estimates PRB 8800 rising from \$10.00 per ton in 2009 to \$14.00 in 2012. NYMEX Futures (March 1, 2010) is reflecting a price movement of \$11.10 per ton in April 2010 to \$14.50 in December 2012. See also: Coal and Energy Price Report, *Powder River Basin prognostication has Arch seeing way to lucrative future,* Volume 12, No. 74, April 20, 2010. Arch's view is more aggressive than NYMEX futures. These market price projections (which are used to establish the value of the two largest publicly traded coal producers in the nation and to set market prices for daily coal trades) are higher than the reference case coal prices that PGE has used in its IRP analyses.

reserves in the PRB Region.[29] The USGS study has raised many questions, but perhaps most important for the PGE Integrated Resource Plan is that it focused on the Powder River Basin. The report demonstrates that the costs of production to continue to mine coal at its current rate will become significantly more costly due to growing geological complexity. The economic modeling and detailed stripping ratio data provided in the study show that the more intensively PRB resources are mined, the more rapidly the structure of production costs increase.

Coal quality also will become more of an issue in the future. Heat rating, and other coal quality factors, will need to be carefully monitored as resource depletion and mine switching are likely to be more frequent occurrences for institutional consumers of coal products. For these reasons, the IRP's assumption that PRB 8800 Btu/lb coal is in higher demand than the 8400 Btu/lb coal it uses and is planning to use (and therefore PGE is less at risk, presumably) is at best a temporary price and quality advantage.

The USGS report prompted press coverage in the Wall Street Journal that uncovered the fact that: a) the United States Energy Information Agency concurred with the findings of the USGS study and was revising the methodology by which the nation's coal reserve levels were being calculated; b) one of the nation's largest coal producers agreed with the findings of the study; and, c) another large power generator had purchased its own mine due to risks and uncertainties it perceived with the traditional mining industry.[30]

A recent analysis of PRB coal offered by Arch Coal, a major mine owner in the PRB region, expects intensified mining (beyond its current rate) and sales from the area.[31] The company points to shrinking stockpiles of PRB coal, diminished production of steam coal from Central Appalachia and historic price patterns in the PRB (which indicate a coming period of volatile upward price swings). The company is viewing a $2 to $5 per ton increase in the price of coal in the near to medium term as a realistic estimate of its potential.

The plans for intensified use of the PRB region support the case for more rapid increases in the cost of production of coal in the PRB region. PGE's coal supply projections of an increase of PRB production from 40% to 50% of the nation's coal supply would increase annual production by approximately 90 million tons according to the EIA from the Northern Great Plains region. Arch Coal's long-term view suggests a doubling of these production levels.[32] The USGS analysis that issued its red flag warnings about rising production costs did so assuming 2006 production levels. Even assuming EIA's slow growth rates compared with Arch's more aggressive production estimates by 2015,

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[29] United States Geological Society, *Assessment of Coal Geology, Resources and Reserves in the Gillette Coalfield, Powder River Basin, Wyoming,* Open-File Report: 2008-1020. http://pubs.usgs,gov/of/2008/1202/

[30] Smith, Rebecca, *U.S. Foresees A Thinner Cushion of Coal,* Wall Street Journal, June 8, 2009.

[31] See the Arch Coal, *Investor Presentation,* February 2010, pages 11-14 and 27, 28.

[32] See Arch Coal, Raymond James Conference, November 10, 2009, Slide # 15.

production will have increased by 80 million tons annually from the Northern Great Plains PRB region above 2006 production levels.[33]

All of these developments suggest that PGE's reference case coal prices may be too low and that the price of 8400 Btu PRB coal may be higher than PGE now anticipates.

Finding No. 10. PGE does not appear to have adequately considered the potential costs of complying with new or revised air emissions requirements and the proper disposal and management of coal combustion wastes.

Prudent electric resource planning requires the consideration of costs for new or revised air emissions requirements and the proper disposal and management of coal combustion wastes.

PGE has considered the costs of complying with the Clean Air Act's Best Available Retrofit Technology ("BART") requirement pursuant to the Act's Regional Haze requirements, and has evaluated future carbon regulation, as described above. However, PGE failed to consider the potential capital and operational costs of complying with additional forthcoming air emissions regulations or the potential remedy in *Sierra Club v. Portland General Electric*. PGE's failure to consider the costs of complying with these potentially more stringent air emissions requirements in the IRP biases PGE's evaluation of the costs of its recommended and alternate Action Plans.

1. The Pollution Controls Required as a Remedy for Violations of the Clean Air Act, and Under EPA's New Air Toxics Rule will be More Expensive to Install and Operate than the Pollution Controls Analyzed by PGE in the 2009 IRP.

As an initial matter, the type of equipment PGE proposes to install to satisfy the BART and reasonable further progress requirement is not the "top-of-the-line" equipment available to reduce the emissions identified today. This is an important point because compliance with new or revised emissions standards or court injunctive relief may increase the already significant costs of retrofitting and operating the Boardman plant into the future. During the April 26, 2010, presentation by PGE regarding the 2009 IRP, Company spokesman Jim Lobdell indicated that the remedy for the *Sierra Club v. Portland General Electric* lawsuit could result in installation of controls at Boardman, assuming the company is liable for violating the Clean Air Act. As explained below, Mr. Lobdell is right.

First, if the plaintiffs prevail in their lawsuit, the company will have to comply with stringent New Source Performance Standards and Best Available Control Technology (BACT) requirements at the Boardman plant.[34] For example, the applicable New Source Performance Standards mandate a scrubber for flue gas desulfurization operated to reach

[33] Energy Information Administration, *2009 Energy Outlook, Supplemental Tables 120-121*

[34] *See Sierra Club v. Portland General Electric, Co.,* Civ. No. 08-1136-HA, Complaint, (alleging violations of 42 U.S.C. § 7411.and 42 U.S.C. § 7475).

a 90% reduction in actual emissions,[35] and immediate compliance is required. Oregon's BART rule mandates only an 80% reduction in actual emissions.[36] Both these emissions reductions requirements far exceed what PGE now proposes in its petition to DEQ for a new BART rule, however, which would provide only a 2% reduction from actual emissions for sulfur dioxide.

In addition to New Source Performance Standards, the plaintiffs in *Sierra Club v. Portland General Electric* have also alleged violations of the new source review program in Oregon.[37] One of the remedies for these violations is that PGE would have to install BACT and operate in compliance with a BACT emissions limitation for both sulfur dioxide and nitrogen oxides. New Source Performance Standards, the 90% control requirement for sulfur dioxide discussed above, are the *floor* for a BACT determination, which requires the maximum degree of pollution reduction achievable at the plant, taking into account a variety of factors including costs. Recent BACT determinations for coal-fired power plants require a 98-99% reduction in sulfur dioxide. For nitrogen oxides, BACT would undoubtedly require some add-on pollution control equipment, most likely a Selective Catalytic Reduction ("SCR") unit that would decrease nitrogen oxide emissions by closer to 93% compared to the 84% reduction required in 2017 under the reasonable further progress requirements.[38] Similar to the New Source Performance Standards, immediate compliance with illegally avoided new source review requirements is required.

Second, EPA is on schedule, and under court order, to promulgate new air toxic emission limitations from coal-fired power plants in November 2011. EPA should have begun regulation of air toxics from electric generating units years ago, but implementation of appropriate controls was delayed by the last administration in Washington, D.C. The litigation around these rules has resolved in the form of a date certain deadline for EPA to promulgate regulations by November 2011. Understanding the regulatory history of these standards is important in discerning the likelihood of PGE's success in escaping regulation under these rules.

In 2005, EPA attempted to remove coal fired plants from the list of facilities subject to regulation under the Clean Air Act's stringent air toxics provisions.[39] EPA promulgated the Clean Air Mercury Rule (CAMR) a few months later to regulate mercury emissions from coal-fired power plants under a less stringent provision of the Clean Air Act.[40] In

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[35] 40 C.F.R. § 60.43Da(a).

[36] OAR 340-223-0030; Implementation Plan Revision: Regional Haze Rule at 154 (June 19, 2009) available at http://www.deq.state.or.us/aq/haze/docs/May09/2008ORRHplan.pdf.

[37] *See Sierra Club v. Portland General Electric, Co.,* Civ. No. 08-1136-HA, Complaint, (alleging violations of OAR Chapter 340, Divisions 28 and 31 (1997); OAR Chapter 340, Division 224 (2003).

[38] Implementation Plan Revision: Regional Haze Rule at 154 (June 19, 2009) available at http://www.deq.state.or.us/aq/haze/docs/May09/2008ORRHplan.pdf.

[39] 70 Fed. Reg. 15,994 (Mar. 29, 2005).

[40] 70 Fed. Reg. 28,606 (May 18, 2005).

New Jersey v. EPA (Feb. 8, 2008), the U.S. Court of Appeals for the DC Circuit vacated CAMR and told EPA that it must promulgate a standard for electric generating units under the more stringent air toxics provisions of the Clean Air Act, and that such rule must cover all toxic air pollutants emitted in significant amounts by coal fired power plants - not just mercury.

EPA was sued when it failed to satisfy this requirement by the deadline set in the statute.[41] The binding settlement of that suit requires EPA to promulgate a new air toxics rule for coal-fired power plants by November 16, 2011**.**

Existing sources at the time that an applicable MACT standard is made effective are required to comply with the standard by an EPA-set compliance date that is "as expeditiously as practicable, but … no … later than 3 years after the effective date of such standard."[42] After that date, it is illegal to operate out of compliance with the federal standard. The law does not allow exemptions from these requirements. There are some compliance extensions available for very specific grounds and for very limited time periods (i.e. one year). The law is clear that extensions outside these narrow circumstances are illegal. In *Natural Resources Defense Council v. EPA*, the D.C. Circuit rejected EPA's argument that it could grant sources additional time to comply, finding that "Congress has … not provided EPA with authority … to extend the compliance date [beyond specific circumstances enumerated in the statute] …."[43]

When EPA issues the air toxics rule, it is reasonable to expect that it will require installation and operation of a sulfur dioxide scrubber that will reduce hydrochloric acid (HCL) and hydrogen fluoride (HF). The rule could require installation and operation of a Selective Catalytic Reduction (SCR) unit to control dioxin, furans, volatile organic compounds, organic hazardous air pollutants, and ammonia. An SCR can also maximize oxidation of mercury, a significant co-benefit for mercury reduction through scrubbing. Thus, the new air toxics rule should not be viewed as just pushing limits lower, but rather as an opportunity for EPA to mandate other technology options currently in use, either alone or in combination with sorbent injection. These other options are available and deployed on many coal-fired power plants, and can achieve higher removal efficiencies for a wider range of air toxics than sorbent injection alone. The costs for compliance with these new air toxics standards either equal or exceed the costs now contemplated for compliance with the BART rule and the reasonable further progress requirements, but speed up the required investments significantly.

The liability trial in *Sierra Club v. PGE* is set for late May 2011. The timing of an ultimate judicial decision on liability and the appropriate remedy is difficult to predict, but could reasonably be expected by early 2012. Compliance with the MACT rule is most likely to be required by 2014, with a possible one-year extension until 2015.

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41 *American Nurses Association v. EPA,* No. 1:08-cv-02198 (D.D.C.).
42 42 U.S.C. § 7412(i)(3)(A).
43 489 F.3d 1364, 1374 (D.C. Cir. 2007).

2. PGE's 2009 IRP Fails to Analyze Costs of Compliance with New Coal Combustion Waste Rules.

PGE has not appropriately considered the costs associated with disposing of its coal combustion wastes. Coal combustion wastes (CCW), also known as "coal ash" or "coal combustion products," consist of fly ash, bottom ash, boiler slag and flue gas desulfurization sludge, and are typically disposed of in landfills and surface impoundments. PGE disposes of its CCW in an on-site dry landfill. Unlike other fossil fuels, coal contains a high amount of non-combustible, inorganic material. In essence, coal is part fuel, part rock: a matrix of hydrocarbons and other minerals and metals, some of which are toxic.[44] The mining process also adds inorganic contaminants when the contents of adjacent strata intermix with the coal.[45]

The burning of coal to produce energy, releases its hydrocarbon content to the atmosphere, leaving behind these inorganic materials, now in considerably higher concentrations.[46] While the primary constituents of CCW are relatively inert,[47] the waste can also contain significant amounts of toxic materials including arsenic, selenium, lead, mercury, cadmium, chromium, boron, thallium, and aluminum.[48] High concentrations of non-toxic materials can also present significant problems. Most CCW, for instance, exhibits high to moderately high pH, carrying a potential to alter the chemistry of surrounding environment, and risk the release of otherwise latent toxic compounds in the surrounding area.[49] CCW also exhibits relatively high concentrations of radioactive material.[50] CCW can contain heavy metals such as arsenic, nickel, cadmium, chromium, lead, manganese, selenium and thallium, as well as sulfates, chlorides, boron,

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44 Stanley P. Schweinfurth, *An Introduction to Coal Quality,* in *The National Coal Resource Assessment Overview: U.S. Geological Survey Professional Paper 1625–F,* Chapter C, 7-9 (Brenda S. Pierce and Kristin O. Dennen eds., 2009) available at http://pubs.usgs.gov/pp/1625f/downloads/ChapterC.pdf.

45 D.F. Pflughoeft-Hassett, E.A. Sondreal, E.N. Steadman, K.E. Eylands and B.A. Dockter, *Production of Coal Combustion By Products: Volumes, and Variability,* in *Proceedings of the: The Use and Disposal of Coal Combustion By Products at Coal Mines: a Technical Interactive Forum* (Kimerly Vories and Dianne Throgmorton eds., April 10-13, 2000), available at www.techtransfer.osmre.gov/NTTMainSite/Library/proceed/ccb2000/ front.pdf.

46 Matthew Pearl, *Recent Developments: The aftermath of the December 2008 Incident in East Tennessee Illuminates the Inadequate Regulation of Coal Ash Impoundments*, 16 U. Balt. J. Envtl. L. 195 (2009).

47 Alan Kolker, Robert B. Finkelman, Ronald H. Affolter and Michael E. Brownfield, The *Composition of Coal Combustion By-Products: Examples from a Kentucky Power Plant*, in *Production of Coal Combustion By Products: Volumes, and Variability, Proceedings of the: The Use and Disposal of Coal Combustion By Products at Coal Mines: a Technical Interactive Forum* 17-18 (Kimberly Vories and Dianne Throgmorton Eds. April 10-13, 2000).

48 *Id.*

49 U.S. EPA, *Human and Ecological Risk Assessment of Coal Combustion Wastes*, 2-2 (2007).

50 Mara Hvistendahl, *Coal Ash Is More Radioactive than Nuclear Waste*, Scientific American, Dec. 13, 2007, available at http:// www.sciam.com/article.cfm?id=coal-ash-is-more-radioactive-than-nuclear-waste.

polyaromatic hydrocarbons (PAHs), benzene, phenols, polychlorinated biphenyls (PCBs), cyanide, dioxins and furans.

EPA has identified risks to human health and the environment from the disposal of CCW in landfills and surface impoundments. For example, EPA's "Coal Combustion Waste Damage Case Assessment" dated July 9, 2007, recognized 24 proven cases of danger to human health or the environment and another 43 "potential" damage cases related to CCW. All but one of the 24 proven damage cases involved unlined disposal units.[51]

A series of spills in late 2008 and early 2009, including the major spill of approximately one billion gallons of CCW at Tennessee Valley Authority's Kingston, TN coal plant in December 2008, drew the nation's attention to CCW storage. Based in part on these spills and an additional series of regulatory determinations regarding improper management and disposal of CCW from coal-fired power plants, EPA recently forwarded regulations to address CCW under the federal Resource Conservation and Recovery Act (RCRA) to the White House.

Specifically, EPA is considering several options including 1) regulating CCW as hazardous waste under Subtitle C of RCRA, which would include a tracking system and federally enforceable permits; 2) regulating CCW as non-hazardous waste under Subtitle D of RCRA, which would include inducements for state solid waste programs and implementation of federal minimum regulations for landfills; 3) a hybrid approach, by which CCW would be considered a solid waste if certain conditions are met, but a hazardous waste if they are not; and 4) another hybrid approach whereby wet CCW (in surface impoundments) would be regulated as hazardous wastes and dry CCW (in landfills) would be regulated as non-hazardous wastes.

EPA also recently announced that it may develop regulations setting financial responsibility requirements for power plants under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA, better known as Superfund), citing, among other things, the "significant cleanup costs that can be generated by this industry sector."[52]

The costs associated with the EPA's anticipated regulation of coal combustion wastes are uncertain and will depend on how EPA classifies the wastes, as well as plant specific factors (that is, wet versus dry storage, lined versus unlined, whether stored on the surface or not). One utility, Progress Energy Carolinas, stated the following in its December 1, 2009 Plan to Retire 550 MWs of Coal Units without SO_2 Controls:

> EPA is currently considering re-characterizing the nature of and regulation of coal combustion products (bottom ash, fly ash and related materials, hereinafter CCPs) in response to TVA's Kingston Plant ash pond

51 U.S. EPA, Notice of Data Availability on the Disposal of Coal Combustion Wastes in Landfills and Surface Impoundments, 72 Fed. Reg. 49714, 49718-19 (Aug. 29, 2007).

52 75 Fed. Reg. 816,822 (Jan. 6, 2010).

> impoundment failure. Speculation is focusing on EPA's regulation of CCPs as a hazardous waste. A narrow usage exclusion may be possible where the finished product of CCP is fully encapsulated. Existing uses that involve land application or unconfined uses may be prohibited. If EPA characterizes CCPs as a hazardous waste or otherwise increases the regulatory requirements applicable to CCPs, the handling, storage and disposal of this material will result in significantly increased costs of operation, and more sophisticated handling equipment and disposal requirements. Classification of power plant CCP operations as activities that produce hazardous wastes as defined by the Resource Conversion and Recovery Act (RCRA) would trigger a number of additional regulatory requirements as well as potential liability associated with closure of impoundments, leachate management and site remediation. Phase out of surface impoundments is under consideration by EPA.[53]

Although the industry cost estimates may be exaggerated in order to dissuade the EPA from regulating CCW as hazardous waste, they do predict significant costs. For example, an October 30, 2009, letter to the Federal Office of Management and Budget from the Utility Solid Waste Activities Group[54] warned that:

> If [coal combustion wastes] were regulated as hazardous wastes, the economic impact on the utility industry would be enormous, resulting in power plant closures, increased electricity rates for consumers, corresponding power reliability concerns, and virtually eliminating all [CCW] beneficial uses.[55]

Testimony before Congress by a representative from EPRI similarly stated that:

> A national coal combustion products regulation will alter the technology and economics of coal-fired power plants. Some owners would decide to prematurely shut down rather than incur the costs of compliance, while others would convert their ash handling and disposal systems and continue to operate in the post-regulation market.[56]

The cost to clean up the damage from the December 2008 release from Tennessee's Kingston plant has been estimated to range from $933 million to $1.2 billion.[57]

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53 Power Plant Study, at pages 7 and 8.

54 The Utility Solid Waste Activities Group is described as an informal consortium of 80 utility operating companies, the Edison Electric Institute and others.

55 Power Plant Study, at page 2.

56 Written Testimony of Ken Ladwig, Senior Research Manager at EPRI, before the Subcommittee on Energy and Environment of the United States House of Representatives, dated December 10, 2009.

57 "TVA Reports 2009 Fiscal Year Third Quarter Results," available at www.tva.gov/news/release/julsep09/3rd_quarter.htm.

Despite the uncertainty associated with the EPA's possible regulation of coal combustion wastes, PGE could reflect this issue in its resource planning analyses. The traditional way to address uncertainty in resource planning is to identify a wide range of the potential costs for key input assumptions.[58] Thus, PGE could identify ranges of the possible costs for the different ways in which the EPA may regulate coal combustion wastes (that is, hazardous or not, etc.) and then apply those ranges of costs in sensitivities in its resource planning analyses.

In sum, it is appears that PGE has not adequately factored into its analyses the potential economic risks of continuing to operate the Boardman plant in the face of new or more stringent air emissions and coal combustion waste management requirements.

Finding No. 11. PGE has not provided persuasive evidence that the retirement of the Boardman plant before the year 2020 would adversely affect the reliability of the electric grid in Oregon or its ability to provide reliable service to its customers. Instead, PGE limited its assessment of reliability to whether it would need to purchase power from the market and not to whether it would be unable to do so or would, in any way, be unable to provide power to its customers.

PGE has explained how it has interpreted reliability in the IRP:

> Throughout this discussion it should be understood that the loss of load probability metrics calculated are best interpreted as indicators of *market dependence*. Reliability in this IRP is interpreted to mean, "To what extent can PGE rely on its own and contracted resources to meet load?" Portfolios that are more reliable in this sense are less exposed to fluctuations in market price and hypothetical curtailment events in which PGE would be unable to secure spot market power needed to meet load.[59]

Consequently, PGE is not measuring how often it might actually be unable to serve load or the magnitude of the loads it would be unable to serve. These are the traditional measures of the reliability of a utility system. Instead, PGE is merely measuring how often it might have to purchase power from another system or merchant generator without any quantification of how often it would be unable to obtain that power.

Moreover, the LOLP figures presented in Figure 11A-12 on page 66 of the IRP Addendum show that the reliability, as measured by PGE, of the Diversified Thermal with Green portfolio is only slightly better than reliability of either the Boardman through 2014 or the Boardman through 2020 portfolios and is actually slightly worse than the reliability of the Boardman through 2017 portfolio. The EUE and Tail Var UE figures

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58 For example, Duke considers ranges of potential CO_2, SO_2 and NOx allowance costs in its IRP analyses.

59 IRP Addendum, at page 39.

presented in Figure 12A-5 on page 97 of the IRP Addendum similarly show relatively comparable levels of reliability between the Diversified Thermal with Green and the four Boardman retirement portfolios. The Diversified Thermal with Green portfolio actually appears to have a slightly higher Tail Var UE than the four Boardman retirement portfolios, suggesting, in PGE's view, a slightly lower reliability.[60]

Finding No. 12. Fuel diversity is an important consideration. However, PGE has failed to demonstrate that the relatively HHI differences between portfolios are in any way significant.

Fuel diversity is an important consideration for a utility like PGE and for a regulatory commission. However, PGE has not offered any evidence to prove that the HHI differences between portfolios shown in Figures 11A-13 and 11A-14 and 12A-6 and 12A-7 are in any way significant. This is especially true for the relatively minor HHI differences between portfolios shown in Figures 11A-13 and 12A-6.

In fact, each of the Boardman retirement portfolios has the high HHIs shown in these Figures precisely because PGE failed to consider any alternative in place of Boardman other than adding a new combined cycle gas-fired unit. All of these portfolios could have had lower HHIs had PGE considered replacement portfolios that included greater investments in energy efficiency and renewable resources plus some new gas or a PPA from a gas-fired unit. Instead, PGE arbitrarily chose to replace Boardman in each portfolio with a comparably sized gas-fired combined cycle unit.

It is even harder to understand the significance of the Technological HHI differences between portfolios shown in Figures 11A-14 and 12A-7. In Figure 11A-14, for example, two of the three portfolios with the lowest HHIs feature new nuclear and IGCC technologies that carry the highest construction cost risk and the greatest technological uncertainty. Moreover, PGE itself believes that relying completely on the market, i.e., the third of the three best performing portfolios in Figure 11A-14, is a very risky strategy. Consequently, a low Technological HHI does not appear to correlate with low risk. Indeed, the opposite could be argued, that is, investing in a large number of untested technologies would be an extremely risky strategy but would lead to lower Technological HHIs.

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60 The reliability of the Boardman through 2014 portfolio actually is better than that of the Diversified Thermal with Green and the Boardman through 2040 portfolios if the year 2014 is excluded. PGE assumes that Boardman would be retired in June of 2014 in the Boardman through 2014 portfolio. For the remainder of that year, PGE would buy replacement power through the market. This, by PGE's definition, decreases the reliability of Boardman through 2014 portfolio in that year. In each of the other years examined by PGE (2012-2013, 2015-2020 and 2025), the reliability of the Boardman through 2014 portfolio is the same as or is better than the reliability of either the Diversified Thermal with Green or the Boardman through 2020 portfolios. This is true for the EUE, Tail Var and LOLP criteria used by PGE to measure reliability. See Attachment A to PGE's response to PEAC Question No. 90.

Increased investments in energy efficiency and renewable resources can reduce a utility's dependence on natural gas without the adverse environmental impacts and financial risks that would be associated with a continued reliance on coal, the most carbon intensive fuel. Repowering older fossil-fired units with newer, more efficient natural gas-fired combined cycle technology is another option. In addition, many utilities regularly limit their exposure to natural gas price uncertainty and volatility through financial or physical hedging.

Finding No. 13. Despite these flaws and biases, the results of PGE's IRP modeling show that investing $510 million in a scrubber and other environment control equipment for the Boardman plant is not part of a lowest cost, low risk resource plan.

PGE has proposed an Action Plan that would retire the Boardman plant at the end of 2020. The Company also has proposed an Alternate Action Plan that would allow PGE to make the $510 million of environmental control investments necessary to operate the plant through 2040 as well as acquiring an additional 15 percent of the Boardman plant output by exercising the Bank of America Lease Option.[61] However, even if the Commission accepts all of the assumptions used by PGE in its IRP analyses, the results of the Company's own modeling shows that continued operation of the Boardman plant through 2040 is not an economically viable part of either a recommended or an alternate Action Plan.

Retirement of the Boardman plant during the period 2014 through 2017 is a lower cost option than operating the plant through 2040

PGE's presented a slide at the March 15, 2010 Technical Meeting that showed the NPVRR for eight early Boardman portfolios that the Company had modeled using its IRP reference case assumptions. These portfolios examined the retirement of the Boardman plant in the years 2014, 2017, 2018, 2019, 2020, 2021, 2022, and 2023. However, PGE did not include the NPVRR for continuing to operate Boardman through 2040.

Figures 12 and 13, below, compare the NPVRR from PGE's Aurora model runs for the scenarios in which the Boardman plant is retired in each of the years 2014 through 2023 and 2040. Although the NPVRR in Figure … are biased by the same assumptions that have been discussed above (e.g., extremely high gas prices, replacement of Boardman by a gas-fired combined cycle unit, and high forecast energy and peak loads), the Company's modeling showed that the NPVRR of each of these early retirement portfolios was lower than the $28,674 (in 2009$ millions) NPVRR of PGE's Diversified Thermal with Green portfolio that assumes continued operation of Boardman through 2040.

61 IRP Addendum, at page 126.

Figure 12: NPVRR of Early Retirement and Boardman through 2040 Portfolios with PGE Reference Case Gas Prices

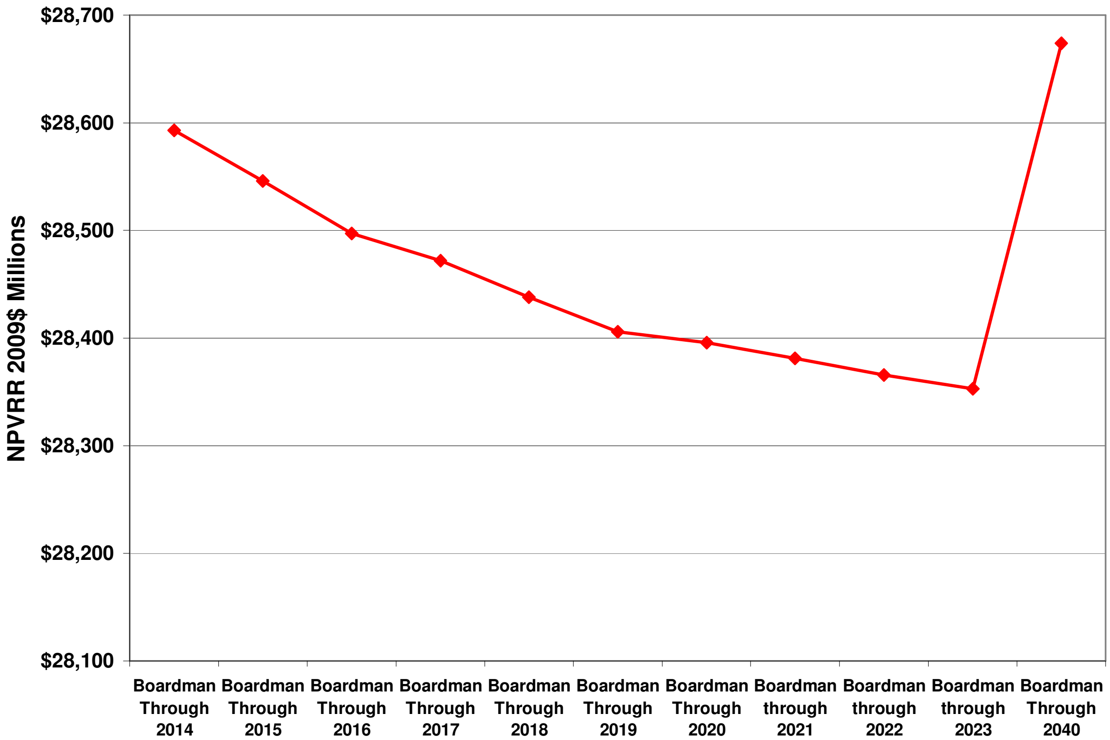
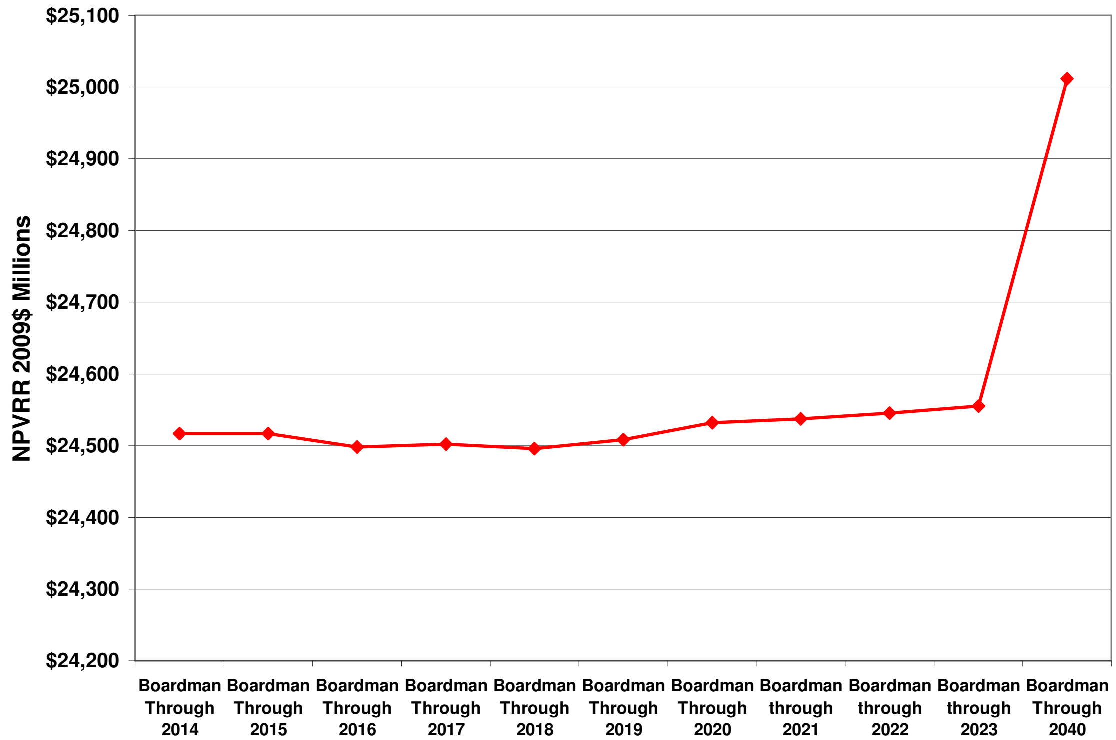


Figure 13 then presents the same comparison but reflects the low gas prices that PGE used in the IRP analyses. These low gas prices are more comparable to the base or reference gas price forecasts from the NPWCC, the Oregon PUC staff and others than PGE's Reference or High IRP gas price forecasts.

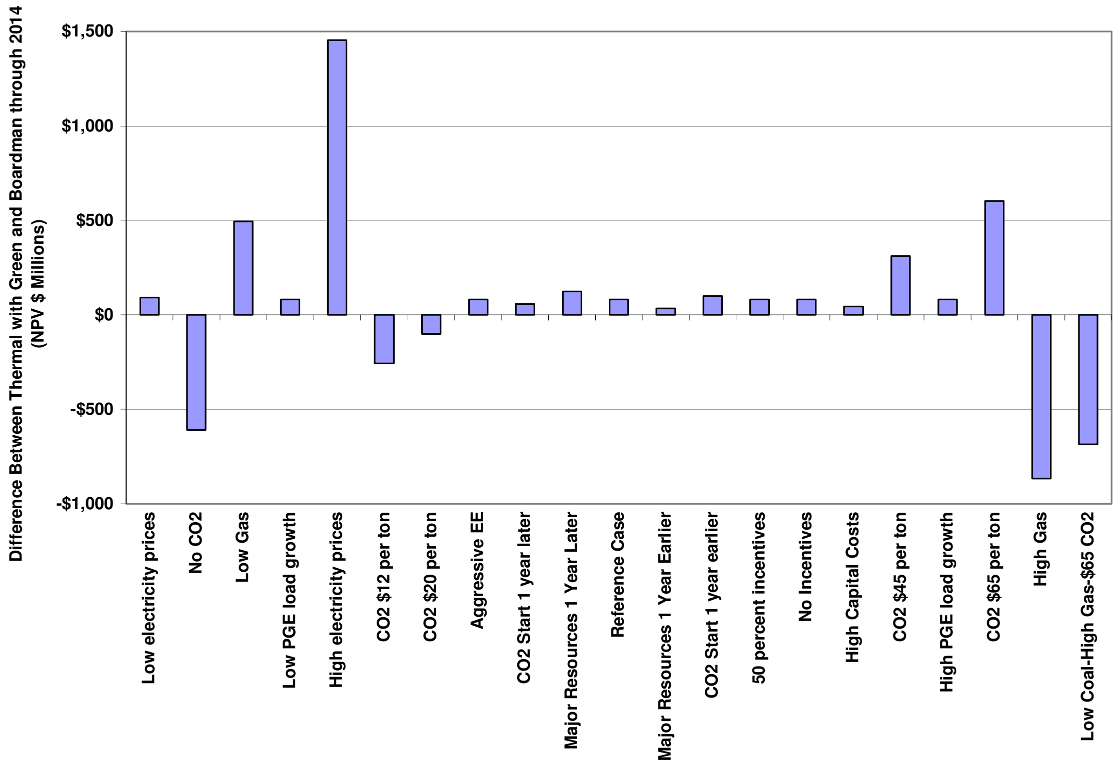
Figure 13: NPVRR of Early Retirement and Boardman through 2040 Portfolios with PGE Low Case Gas Prices



Consequently, the Company's own modeling analyses show that retirement of the Boardman plant in any of the years between 2014 and 2019 is a lower cost option than continued operation through 2040 even with the biased assumptions discussed earlier in these comments. Indeed, when less biased, and more reasonable, gas prices are used, continuing to operate the Boardman plant through 2040 (i.e., the Diversified Thermal with Green portfolio) can be seen to be significantly more expensive than any of the early retirement portfolios.

Figure 14, below, shows the NPVRR differences between the Boardman through 2014 and the Diversified Thermal with Green portfolios in each of the 21 futures scenarios modeled by PGE for the IRP. The Diversified Thermal with Green portfolio is the more expensive option in 16 of the 21 scenarios modeled by PGE.

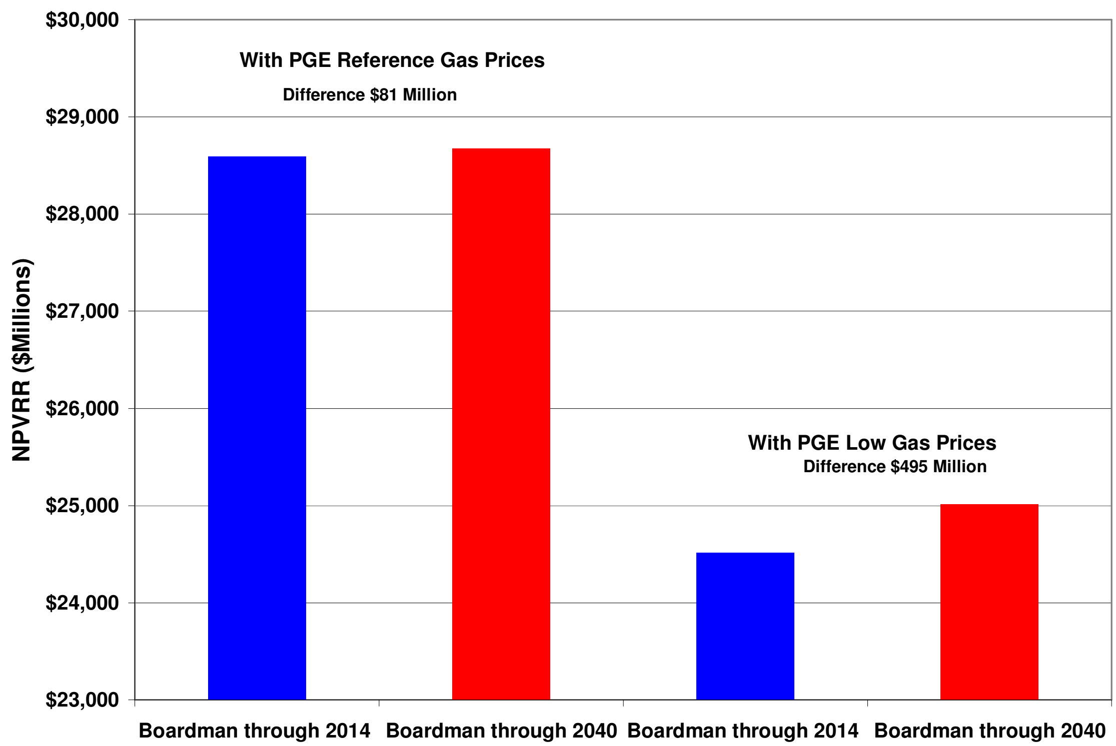
Figure 14: NPVRR Difference between PGE Diversified Thermal with Green and Boardman through 2014 Portfolios (2009$ Millions)



It is important to recognize that the five scenarios in which the Diversified Thermal with Green portfolio is the lower cost option include the two scenarios with completely unrealistic high gas prices and the three scenarios with no CO_2 prices or low CO_2 prices – and the Diversified Thermal with Green portfolio is only significantly lower cost than the Boardman through 2014 portfolio in the more unrealistic scenarios with high gas prices and no CO_2 prices. Thus, in order to accept that the Diversified Thermal with Green portfolio is a lower cost option than retiring Boardman in 2014 it is necessary to accept either that gas prices will be dramatically higher than anyone now projects, that there will be no federal regulation of greenhouse gases at any time between 2010 and 2040 or that federal regulation will lead only to low CO_2 prices.

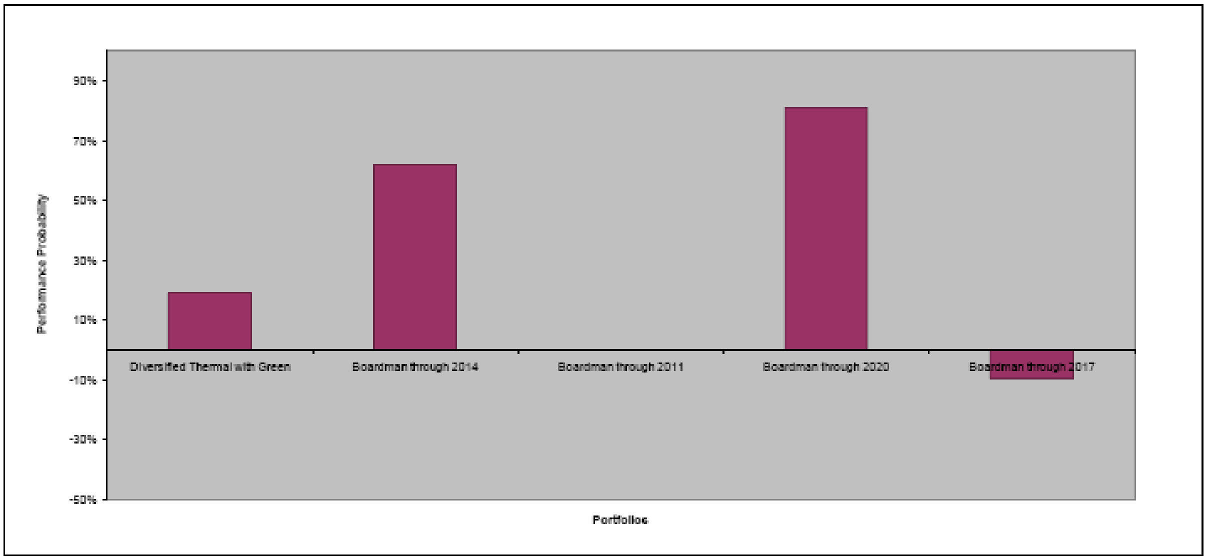
On the other hand, as shown in Figure 15, below, the NPVRR benefit to the Boardman through 2014 portfolio increases to $495 (2009$ Millions) in PGE's low gas price future scenario. This is a more reasonable scenario in which the assumed gas prices are only slightly lower than the current mid NWPCC forecast, the Oregon PUC staff forecast, the AEP 2010 forecast and current NYMEX futures.

Figure 15: Net Present Value Revenue Requirement Benefit to Retiring Boardman in 2014 as Compared to Operating the Plant through 2040 with PGE Reference and Low Gas Prices



In the IRP Addendum, PGE presented Figure 12A-2 with the Combined Probabilities of Good and Bad Outcomes for Boardman Portfolios. This Figure is reproduced below. It shows that the Boardman through 2014 and the Boardman through 2020 portfolios both have significantly higher probabilities of achieving good outcomes and avoiding bad outcomes than the Diversified Thermal with Green portfolio. Unfortunately, the Boardman through 2017 portfolio included in this Figure is the completely unrealistic scenario in which the plant is assumed to be retired immediately after the investments are made in a new scrubber and other emissions controls.

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



PGE states that "Better portfolios have a high probability of *combined* good vs. bad outcomes.[62] Under that criterion, the Boardman through 2014 portfolio certainly is a "better" portfolio than the Diversified Thermal with Green portfolio.

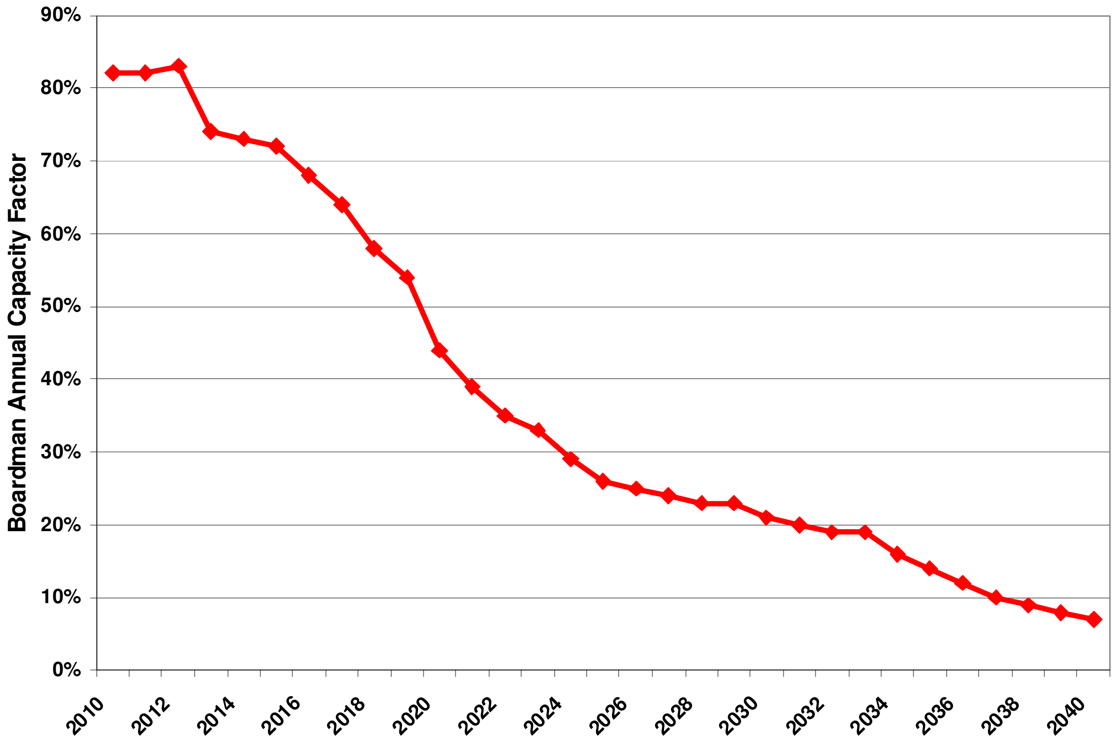
Finding No. 14. The results of PGE's modeling analyses show that by 2020 Boardman will no longer be a baseload generating unit even if $510 million is invested in environmental upgrades.

The Boardman plant has historically been operated as a baseload unit on PGE's system. The results of PGE's IRP modeling analyses shows that this will change, beginning in the 2016-2017 timeframe, when the unit's annual capacity factors would start a slow, inexorable decline.

Figure 16, below, presents the annual Boardman plant capacity factors calculated by the Aurora model for PGE's preferred Diversified Thermal with Green portfolio. As can be seen, by 2020 the Boardman plant would have a capacity factor of only 44 percent which is more indicative of an intermediate unit than a baseload plant and suggests perhaps seasonal dispatch and operation during peak load hours. By 2030, the unit would have a capacity factor of only 20 percent, which suggests less seasonal dispatch and increased dispatch as a peaking unit.

62 IRP Addendum, at page 93.

Figure 16: Boardman Capacity Factors 2010-2040 in Diversified Thermal with Green Portfolio



This steady decline in performance raises serious questions about the prudence of investing $510 million for environmental upgrades on a coal-fired unit that would no longer be operating at the 70 percent to 80 percent annual capacity factors typically achieved by baseload generating facilities.

Finding No. 15. PGE's analyses that purport to show that retirement of the Boardman plant in 2020 would be a lower cost and lower risk option than retirement in an earlier year are biased in favor of continued operation.

PGE claims that the Boardman through 2020 portfolio provides the best combination of cost and risks for customers when compared to other viable portfolios.[63] However, this claim is not credible because the analyses on which it is based are biased by each of the assumptions that have been previously discussed in these comments. This is true for each of the analyses whose results are presented in Figures 12A-1, 12A-2, 12A-3, 12A-4, 12A-8, 12A-9, and 12A-10 in the IRP Addendum and at pages 31 through 34 of PGE's Presentation at the OPUC's April 26, 2010 Public Meeting.

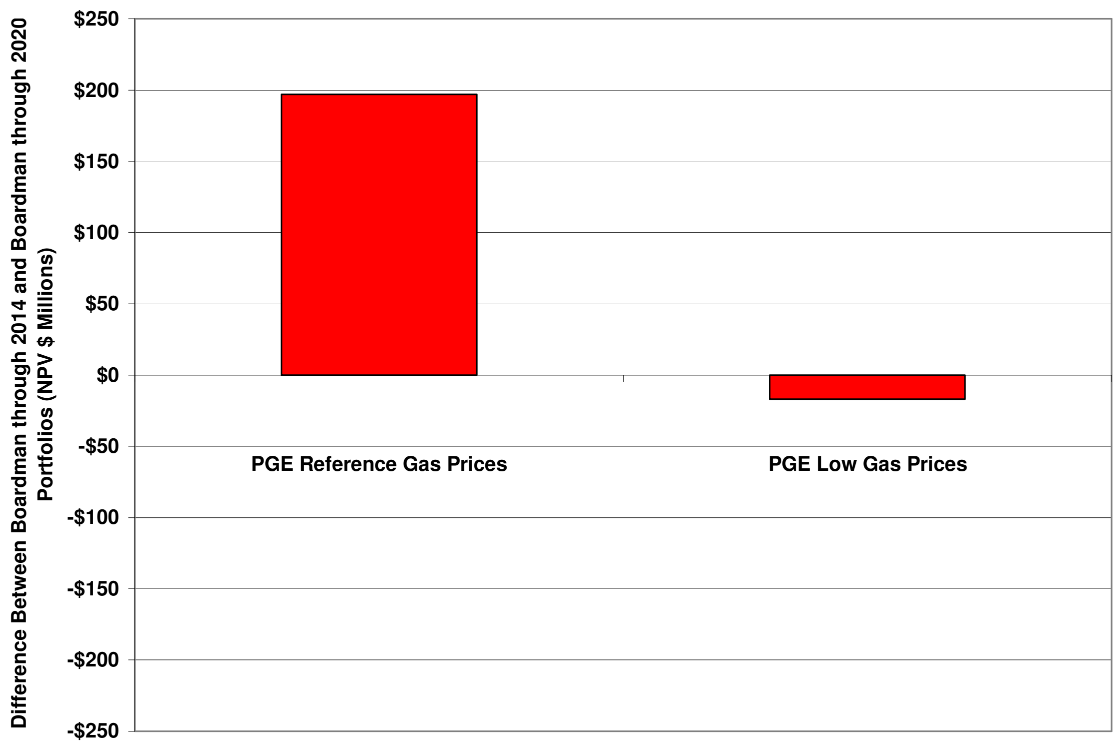
63 IRP Addendum, at page 88.

In particular, the very high natural gas prices used by PGE and the Company's assumption that Boardman would be immediately replaced by a natural gas-fired combined cycle unit together bias the comparisons between retiring the Boardman plant in 2020 and earlier years. Indeed, PGE itself notes the following in the IRP Addendum:

> "Boardman through 2014" and "Boardman through 202" 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.[64]

For example, as shown in Figure 17, below, the $197 million (in 2009$) NPVRR benefit shown for the Boardman through 2020 portfolio with PGE's reference case gas prices becomes a $17 million (in 2009$) benefit for the Boardman through 2014 portfolio with PGE's low gas prices.[65] As shown in Figure 1 and Figure 4, above, PGE's low IRP gas price forecast is only moderately lower than the reference case forecasts from NWPCC, the Oregon PUC staff, AEO 2010, and PIRA 2010.

Figure 17: NPVRR Differences between PGE Boardman through 2014 and Boardman through 2020 Portfolios (2009$ Millions)



64 Id, at page 101.
65 Table D Addendum-2, Scenario Analysis Detail, IRP Addendum, at page 134.

The risk assessments presented in Chapter 12 of the IRP Addendum (and PGE's April 26, 2010 Presentation to the OPUC) are similarly biased because, as has been discussed earlier in these comments, two of the four worst performing scenarios for the Boardman through 2014 portfolio are those with the extraordinarily high gas prices in PGE's "High Gas Price" forecast.

In addition, PGE's claim that a 2020 closure would have "over $600 million lower cost than [a] 2014 case (nominal $)" and "an NPV benefit for customers of over $400 million" also are not credible because they too are based on (1) PGE's high reference case natural gas prices, (2) PGE's arbitrary assumption that Boardman would be immediately replaced by a gas-fired combined cycle unit and (3) by PGE's failure to consider whether there were lower cost options for replacing Boardman including additional spending on energy efficiency, addition renewable resources and a mid- to long-term PPA.

PGE has claimed that the lower rates from delaying the retirement of Boardman until the end of 2020 are driven by:

- Lower power costs 2014-2020
- Does not accelerate depreciation between 2011 and 2014
- Delays capital investment for a replacement source[66]

A review of PGE's workpapers reveals that the Company's assumption that a new capital-intensive replacement source of power would be required immediately after Boardman is retired is the major factor leading to the asserted higher cost of the Boardman through 2014 portfolio during the years 2010 through 2021. This is due to the heavily front-loaded capital costs from the new combined cycle unit that PGE assumes would be added in 2015.

Confidential Table 3, below, compares the difference in revenue requirements for the years 2010 through 2021 for the Boardman through 2014 and the Boardman through 2020 portfolios, disaggregated by major cost categories. A positive number in Table 3 means that the Boardman through 2014 Portfolio is more expensive than the Boardman through 2020 Portfolio. A negative number means that the Boardman Through 2014 Portfolio is less expensive.

Table 3: Boardman through 2014 vs. Boardman through 2020 in the Years 2010 through 2021 [Confidential. Please See Page 45 and 46 of Confidential Version]

[66] PGE March 15, 2010 Presentation on the *Boardman 2020 Alternative*, at Slide No. 35.

The bottom line is that PGE should examine whether there are less expensive alternatives for replacing the Boardman plant than adding a new combined cycle unit if the plant were retired in 2014, 2015, 2016, 2017, 2018 and 2019.