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August 10, 2010

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

Re: LC 48

Attention Filing Center:

Enclosed for filing in the captioned docket are an original and ten copies of Portland General Electric Company's Reply Comments.

This is being filed by electronic mail with the Filing Center.

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

Thank you in advance for your assistance.

Sincerely,

V. DENISE SAUNDERS
denise.saunders@pgn.com

VDS:cbm
Enclosures
cc: LC 48 Service List (w/enclosures)

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **REPLY COMMENTS** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No. LC 48.

Dated at Portland, Oregon, this 10th day of August, 2010.

V. Denise Saunders

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. LC 48

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2009 Integrated Resource Plan.		**REPLY COMMENTS**

INTRODUCTION

Pursuant to the ALJ Prehearing Conference Memorandum dated July 8, 2010, Portland General Electric (PGE) submits these comments in response to the approximately thirty-two parties who commented on the 2009 Integrated Resource Plan (IRP). We appreciate the interest parties have shown in our IRP. Many of these parties participated in some or all of the nine PGE workshops conducted over the past nearly two years, and several submitted initial comments on our draft IRP filed in September 2009. Their collective contributions have helped us refine our IRP and resulting Action Plan.

We have organized our response to address those areas for which Intervenors express common interests including Action Plan items (Boardman emissions controls and Cascade Crossing), load growth (including energy efficiency), fuel price forecasts, emissions regulation, and analytical approach.[1] Accordingly, we have structured our response into the following sections:

- Executive Summary
- Boardman
- Cascade Crossing
- Resource Needs, including Load Growth and Energy Efficiency
- Fuel Price Forecasts
- Wind Integration
- Power Purchase Agreement Market Reliance (proposed by some commentators)
- Renewable Portfolio Standards Compliance
- Fuel Emissions (including Carbon regulation compliance and costs)
- Portfolio and Risk Analytics Considerations

[1] Some of the parties submitted unusually long and detailed comments. While we believe that we have addressed all material comments in this Reply, we note that our silence on a particular point raised in the parties' initial comments should not necessarily be construed as a concession that we feel the point is valid.

1. Executive Summary

a. Boardman

The vast majority of comments concerned PGE's proposed actions with regard to the Boardman generating plant. A broad spectrum of parties supported PGE's recommended future operating plan for Boardman that contemplated ceasing coal-firing operation by the end of 2020 as described in the IRP Addendum and hereafter referred to as "BART II." Implementation of BART II was contingent upon Environmental Quality Commission (EQC) approval of PGE's petition to amend the Oregon Regional Haze Plan. On June 17, 2010, the EQC denied PGE's petition and directed the Oregon Department of Environmental Quality (DEQ) to commence a rulemaking to determine other alternatives for amending the Oregon Regional Haze Plan. On June 28, 2010, DEQ released a preliminary proposal that would provide three new options for installing emissions controls at Boardman. PGE submits an analysis of those options in these Reply Comments.

Our analysis shows that the new DEQ options either cannot be implemented for operational or regulatory reasons or they offer an extremely poor outcome for our customers in terms of cost and risk. PGE has proposed an alternative to the DEQ options (called "BART III") which represents a balanced and reasonable outcome that will benefit both the environment and our customers. Our BART III proposal modifies the BART II proposal included in our IRP Addendum to capture additional interim control benefits substantially reflecting DEQ's suggested control options.

PGE's BART III proposal ceases coal-fired operations at Boardman in 2020 and implements the more stringent reductions called for in the DEQ options at a cost to our customers of $103 million above PGE's original BART II proposal, while retaining the core objectives of reducing customer rate impact and providing more time for a transition. PGE requests that the Commission acknowledge its BART III proposal as being least cost and least risk and the best option for the company and its customers.

Implementation of our BART III proposal must be contingent on EQC approval. Should the EQC not accept our BART III proposal, then PGE requests that the Commission acknowledge the only remaining realistic and responsible proposal that DEQ has allowed us: installation of all DEQ-recommended BART and Reasonable Progress controls and operation of the plant on coal until 2040 or beyond (BART I).

PGE's BART III proposal is not contingent on resolution of the EPA's new Maximum Achievable Control Technology (MACT) standards or the pending litigation (brought by Sierra and others). We recognize the risk remains that the outcome of either MACT or the pending litigation could require PGE to install controls at Boardman similar to those required under DEQ's BART I proposal to operate the plant through 2040 under the current Regional Haze Plan. We request that the Commission acknowledge that it is prudent for PGE to proceed with its BART III proposal despite these risks.

b. Cascade Crossing

PGE also received several comments regarding the Cascade Crossing Transmission Project. This project responds to the Commission's concurrence with the Company that additional transmission capacity is needed to support acquisition and development of renewable resources and its directive to "work with BPA and others to develop transmission capacity over the Cascades." *Portland General Electric Company,* Docket LC 33, Order No. 04-375 at 12 (July 20, 2004). While PGE's need for additional transmission to access resources on the east side of the Cascades has grown, BPA has virtually no available long-term firm transmission that would allow PGE to access these resources. The need for this transmission facility has been confirmed by the fact that PGE has received interconnection requests for approximately 2300 MW of winter generating capacity, at least half of which is from third parties. This level of interest far exceeds the anticipated capacity of a single-circuit 500 kV facility, making it apparent that the development of the double-circuit configuration is the most prudent course of action.

The need for Cascade Crossing does not depend on the continued operation of Boardman or its replacement with another generating facility. For example, even if Boardman were to cease operations and no additional generation was developed at that site, PGE would *still* need to construct a line capable of transmitting 1907.4 MW to satisfy the remaining interconnection requests in PGE's queue. In addition even considering conservative assumptions about BPA's future transmission rates and taking into account current operational limitations Cascade Crossing presents a better operational and economic option for PGE's customers. It will also enhance PGE's and the region's electric grid reliability.

Therefore, given PGE's need to access new generation to meet its customers' energy demand reliably and cost effectively; the amount of pending interconnection requests from third-parties; and the requirement to meet the State's Renewable Energy Standard, construction of Cascade Crossing as a new double circuit transmission line is a prudent investment for our customers.

c. Other Comments

Other substantive comments offered by parties provide no persuasive grounds for the Commission to decline to acknowledge PGE's Action Plan. The parties' concerns regarding PGE's load forecast are wrongly focused on (i) the low load growth in the last decade and (ii) regional load data that include areas with substantially different load growth characteristics than PGE's largely urban service territory. Moreover, any disagreement with PGE's load forecast does not significantly alter PGE's future need for additional resources, as much of the need is driven primarily by the expiration of existing supply contracts.

Several intervenors commented that the gas price forecast used in PGE's 2009 IRP was too high compared to more recent forecasts that have been released. We acknowledge that gas price forecasts released in mid-April show a decline. We recognize that gas price forecasts, like gas prices themselves, change over time and those changes can be dramatic. In the span of roughly a decade we have seen long-term gas forecasts swing from relatively inexpensive to very expensive and back again resulting in the high price volatility recognized in the natural gas market. Each of these changes in the long-term forecasts was based on research and information about developing and future supply and demand. However, each time we have seen a forecast for tight or abundant gas supply, the forecast has proven incorrect within a few years. We therefore must be careful to avoid making planning decisions based on a gas forecast of either "cheap and abundant forever" or "scarce and really expensive forever." History has shown that inevitably new facts and information emerge, driving supply and demand to find a new equilibrium that can cause both the future outlook and actual gas prices to change.

In the context of this IRP, there are further grounds for a cautious approach. Gas price risk is highly asymmetric in a number of unfavorable ways for both PGE and its retail customers. There is a clear limit to how low natural gas prices can go, bounded by the cost of extraction and transportation. Current forecasts therefore have little downside risk because prices are relatively low today and price reductions cannot exceed the price floor set by extraction and transportation costs. Moreover, PGE's reliance on natural gas serves to increase its exposure to the risk of higher-than-forecast gas prices. In particular, in the case of a 2015 Boardman closure, approximately 55% of our *energy* resource mix would consist of natural gas. PGE's exposure to higher than forecast gas prices would become substantial. Accordingly, we believe that the Commission should be cautious about allowing the current optimism regarding natural gas prices to unduly influence our approach to resource planning.

2. Boardman

a. Background

PGE submitted its IRP Addendum to seek acknowledgement of a revised Action Plan based on a new preferred portfolio – Boardman through 2020 (BART II). The new portfolio was prepared in response to a request from several IRP stakeholder groups that we consider a portfolio in which we terminate coal-fired operations at Boardman in 2020 to meet emissions requirements under the federal Clean Air Act Regional Haze Rules. Our proposal to cease coal-fired operations twenty years early is especially notable given that the Boardman plant performs within the top quintile for coal plant efficiency (based on heat rates) within the U.S., is younger than about three-quarters of the U.S. coal fleet, and is a large and low-cost baseload resource in PGE's generating fleet. We believe our proposal, if implemented, would set a precedent that could help shape a national strategy for power plant emissions reductions.

PGE's BART II proposal offered several advantages to the limited alternatives available under existing environmental rules (either installing emissions controls and running the plant to 2040 or shutting the plant down in 2014):

- when compared to both the 2014 and 2040 options, it minimized both costs and rate impacts to our customers;
- when compared to the 2014 and 2040 options, it offered a more reasonable transition period that would allow PGE to consider a broader range of replacement supply options for Boardman;
- when compared to a 2014 closure, it avoided undermining PGE's ability to maintain system reliability;
- when compared to a 2014 closure, it avoided a large accelerated amortization of the existing investment basis in the Boardman plant;
- when compared to a 2014 closure, it provided time for an orderly transition for employees and the community;
- when compared to a 2040 closure, it avoided significant expenditures for reasonable progress regional haze controls;
- when compared to a 2040 closure, it ceased 100% of all plant coal-related emissions 20 years sooner than originally planned; and,
- when compared to a 2040 closure, it avoided potential CO_2 compliance exposure in the years after 2020 when initially mild proposed carbon regulation, becomes more costly, reflecting increasing CO_2 reduction targets.

Shortly before filing the IRP Addendum, PGE submitted a petition to the EQC to amend the Oregon Regional Haze Plan (BART II Petition). We explained in our IRP Addendum that EQC approval of the BART II Petition was necessary for PGE to implement its Boardman through 2020 portfolio. On June 17, 2010, the EQC denied PGE's petition and directed the DEQ to commence rulemaking to determine other alternatives to the current BART/RP requirements in the Regional Haze Plan. On June 28, 2010, DEQ released a preliminary proposal for informal comment that would provide three proposed new options in addition to the existing BART I requirements.

Our analysis shows that the new DEQ options either cannot be implemented for operational or regulatory reasons or offer an extremely poor outcome for our customers in terms of cost and risk. Accordingly, PGE has proposed an alternative to the DEQ options (BART III) which represents a balanced and reasonable outcome that will benefit both the environment and utility customers and meet all BART and Reasonable Progress Requirements. We describe the DEQ options and PGE's alternative option below and provide portfolio analysis of the results. We also respond to additional issues related to Boardman that were raised in parties' initial comments.

b. <u>Description of DEQ Options</u>

DEQ is proposing three new options as amendments to its existing Regional Haze Rules. These rules implement the federal requirement that Oregon develop a Regional Haze Plan for submittal to EPA and approval into the State Implementation Plan. The regional haze plan must include a determination of Best Available Retrofit Technology (BART) for each BART-eligible source in the state that emits any air pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I area. 40 CFR § 51.308(e)(1)(ii). The BART determination specifies emissions limits but does not mandate what controls must be installed to meet those emissions limits. We provide below DEQ's description of the controls it believes would be required under each of its new proposed options. We also provide DEQ's assumptions as to closure dates. While neither the DEQ nor EQC has the authority to set a closure date for the Boardman Plant, PGE can volunteer to accept a premature closure, which DEQ is then required to take into account in determining BART.

i. DEQ Option 1(DEQ 2020)

This option requires installation of new low-nitrogen oxide (NOx) burners with a modified overfire air control system in 2011 at an overnight capital cost of $32.8 million; installation of sulfur dioxide (SO_2) controls consisting of semi-dry flue gas desulfurization (dry scrubbers) in 2014 at an overnight capital cost of $289.9 million; and installation of selective non-catalytic reduction (SNCR) in 2014 at an overnight capital cost of $12.2 million. This option assumes that the plant would cease coal-fired operations in 2020.

ii. DEQ Option 2 (DEQ 2018)

This option requires the same low NOx burner system in 2011 and SNCR controls in 2014, but replaces the dry scrubbers in 2014 with a Dry Sorbent Injection system (DSI) at an overnight cost of $22.6 million with yearly operation and maintenance (O&M) of $12.4 million. This option assumes that the plant would cease coal-fired operations in 2018.

iii. DEQ Option 3 (DEQ 2015)

This option requires the same low NOx burner system in 2011, but does not require the installation of SO_2 scrubbers, SNCR or DSI. This approach is based on a federal requirement to install BART controls within five years of approval of the state regional haze plan. Oregon's 2009 Regional Haze Plan is expected to be approved by the EPA in late 2010 or early 2011. If PGE chooses not to install any SO_2 BART controls, federal rules would require the Boardman plant to shut down in five years, or by late 2015 or early 2016.

All of the DEQ options also include installation of mercury controls at a capital cost of $7.7 million.

The following tables show the control options and their respective capital and O&M costs, timing and heat rate impacts: Overnight capital costs are in nominal dollars, O&M costs are in $2010, and all are 100% share:

Controls	Controls Timing and Cost, $ Millions, 100% Share					
	In-Service Year	EPC Contract by:	Overnight Capital Cost (nominal sum)	Incremental Fixed O&M/Yr.	Inc. Var. O&M/Yr. @ 85% CF	Heat Rate Impact (%)
Low NOx Burners / OFA	July 2011	Spring 2010	$ 32.8	$ 0.7	$ -	Negligible
Mercury Control	July 2012	Spring 2010	$ 7.7	$ 0.4	$ 5.6	Negligible
Lower-sulfur Coal	July 2014	NA	$ -	$ -	$ 1.5	None
DSI via SBC + Lower-sulfur Coal	July 2014	Summer 2012	$ 22.6	$ 0.3	$ 12.4	0.1
Semi-Dry FGD (Scrubber with Fabric Filter)	July 2014	Spring 2011	$ 289.9	$ 2.2	$ 4.3	1.4
SNCR	July 2014	Spring 2013	$ 12.2	$ 0.3	$ 3.0	Negligible
SCR	July 2017	Spring 2014	$ 180.1	$ 0.4	$ 2.3	0.7

Controls	Controls/Closure Options*					
	PGE 2020 BART II (Addendum)	DEQ 2015 (DEQ Opt. 3)	DEQ 2018 (DEQ Opt. 2)	PGE 2020 BART III (Proposed)	DEQ 2020 (DEQ Opt. 1)	DEQ 2040 BART I
Low NOx Burners / OFA	X	X	X	X	X	X
Mercury Control	X	X	X	X	X	X
Lower-sulfur Coal	X					
DSI via SBC + Lower-sulfur Coal			X	X		
Semi-Dry FGD (Scrubber with Fabric Filter)					X	X
SNCR			X	X	X	
SCR						X

* Dates for IRP analysis purposes are at year-end.

c. The DEQ Options Cannot be Implemented

On July 30, 2010, PGE submitted comments to DEQ offering corrections to technical and methodological flaws in DEQ's analysis supporting its options. See PGE DEQ Comments (attached hereto as Attachment 1). While we believe that DEQ shares our intention of seeking an appropriate alternative to implementation of full controls and continued operation of the Boardman Plant through 2040, we believe the agency has reached a number of invalid conclusions that render all three of the new options unworkable.

Option 1, which anticipates that coal-fired operations would cease in 2020, would require installation of the flue gas desulfurization scrubbing at roughly $290 million for only a few years of operation and, thus, is simply too expensive for our customers. In fact, the analysis we present below shows that it is the single most expensive option proposed.

Option 2, which anticipates that coal-fired operations cease in 2018, requires the installation of DSI. However, DSI has not shown to be technically feasible under EPA requirements because it has not been installed and operated successfully on a long-term basis for a boiler as large as the Boardman Plant at the SO_2 reduction levels envisioned. *See,* PGE DEQ Comments at 9-10. In addition, as a result of proposed regulatory changes, it appears that a DSI system cannot be permitted under new DEQ emergency rules governing fine particulate matter ($PM_{2.5}$) at the SO_2 reduction levels envisioned. *See,* PGE DEQ Comments at 10-12. Alternatively, even if the DSI were permittable, the

DEQ BART analysis does not take into account any additional controls that might be needed to meet the $PM_{2.5}$ emergency rules. *See,* PGE DEQ Comments at 13.

Option 3 suffers from the same shortcomings of the Sierra[2] proposal to close Boardman in 2014: it will perform only somewhat better than 2014 does on a cost basis while it does not allow sufficient time to put a long-term replacement resource in place. The average time to construct a CCCT is six to seven years, and as we discuss in detail in Section 7 of these Reply Comments, we simply cannot know whether we will be able to purchase firm energy and capacity for replacement power or, if we can, whether it will be offered at an affordable price. Further, Option 3 does not provide the additional time for non-wind renewable markets time to mature as do the options with later closures. Simply put, DEQ's Option 3 is a plan that is costly and more risky for our customers. It also does not allow sufficient transition time for plant employees and the Boardman community.

We note that Sierra, the strongest advocate for a 2014 closure, has supported coal plant closures in 2020 and even later in other states. For example, according to a Sierra Club press release, Sierra Club applauded an announcement that the City of Los Angeles would eliminate the use of coal by 2020. *See,* Attachment 2 at 1. Another Sierra Club press release expresses support for coal use through 2027 in neighboring Pasadena. *Id.* at 2. In Texas, Sierra Club's Lone Star Chapter issued this statement regarding Austin Energy's coal-powered plant: "'...Sierra Club agree[s] that we can and must get out of the coal plant by 2020,' noted Public Citizen's Matthew Johnson who served on the [Austin Generation Resource Planning] Task Force." *Id,* at 3-4. In May, when UNC-Chapel Hill announced it would phase out coal use at its co-generation plant by 2020, "Beyond Coal" national director Bruce Nilles described the move as a "remarkable step." *Id.* at 5. Also, earlier this year, according to a McClatchy news report, Mr. Nilles is reported to generally favor a 2030 phase-out date for coal. *Id.* at 6-8. It is unclear why Sierra is supportive of reasonable transition dates for coal plants in other areas but continues to push for an unrealistic and risky timeline in Oregon with apparently scant concern about the economic impacts on Oregon ratepayers and the Boardman community.

In addition to the implementation barriers described above, DEQ Options 1 and 3 (and Option 2 – to the extent additional controls are needed to meet the $PM_{2.5}$ emergency rules) will result in unnecessarily sharp near-term rate increases for our customers

d. PGE's BART III Proposal is Better in Terms of Cost, Risk and Environmental Impacts

In our DEQ Comments, we have offered the new alternative BART III proposal to address key provisions of the Regional Haze rules and the BART guidelines to accomplish a reasonable 2020 closure of the Boardman Power Plant. Our alternative proposal modifies the 2020 proposal included in our IRP Addendum to capture additional interim control benefits, substantially reflecting DEQ's concerns and suggested control options for its Option 2. Specifically, we propose operation on reduced sulfur coal, low-NOx burners, modified overfire air ports and SNCR through 2020 with a pilot study of

[2] PGE provides a list of abbreviations used to identify parties in Appendix A.

DSI technology. Contingent on the results of pilot testing, PGE would commit to meeting a 0.4 lb SO_2/MMBtu limit through 2020 using DSI. If this option is considered BART, DEQ would need to provide a procedure for establishing an alternative SO_2 limit based on the testing. The limit would be adjusted if PGE's pilot testing demonstrated that operation of DSI could not reach 0.4 lb SO_2/MMBtu, when operating in conjunction with SNCR and the mercury controls, without resulting in an increase in the hourly capacity to emit particulate matter or triggering Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ (assuming the same level of operation currently reflected in the Boardman Plant's plant site emission limits).

Put differently, PGE proposes to adopt the DEQ Option 2 set of emissions controls while operating somewhat longer than DEQ proposes, inclusive of SO_2 reductions via DSI to the higher of 0.4 lb SO_2/MMBtu or the level prior to which $PM_{2.5}$ is triggered. PGE's plan retains the best aspects of both the new DEQ Option 2 and PGE's original 2020 proposal by adopting ALL of the additional emissions reduction controls that DEQ recommends in their Option 2 proposal AND maintaining the important advantages for our customers and allow consideration of improved renewables penetration and diversity that the additional time brings. It is a plan that is both less costly and less risky, while providing an improved opportunity for long-term environmental advantages and a reasonable transition time for the plant employees and local communities.

e. Description of New Portfolios

For purposes of portfolio analysis, we have added four new portfolios: DEQ2015 (DEQ Option 3), DEQ2018 (DEQ Option 2), DEQ2020 (DEQ Option 1) and a new PGE2020 BART III proposal. We have also eliminated two portfolios found in the Addendum that are no longer under consideration: the Boardman portfolios that propose closures in 2011 and 2017. All other previous portfolios remain the same. (unless Oregon CO2 Goal portfolio or otherwise indicated, all portfolios operate Boardman until 2040, and all except for the Oregon CO_2 Compliance Portfolio install all required BART I controls). Below, we describe the new generating resources included in the portfolios, in the order that the portfolios are modeled[3]. The portfolios are:

1. *Market*
2. *Natural Gas*
3. *Wind*
4. *Diversified Green*
5. *Diversified Thermal With Wind*
6. *Bridge (2015) to IGCC in Wyoming (2019)*
7. *Bridge (2015) to Nuclear in Idaho (2019)*
8. *Diversified Green with On-Peak Energy Target*

[3] See the IRP Addendum for a description of the portfolios that have not been changed.

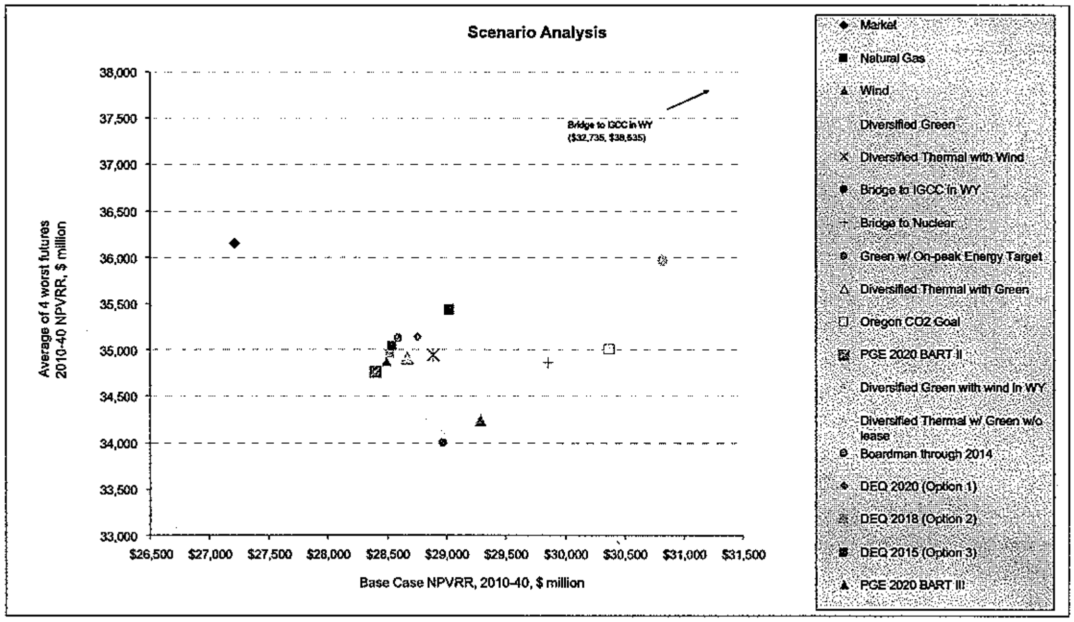
9. *Diversified Thermal with Green (BART I)*
10. *Boardman through 2014*
11. *Oregon CO_2 Goal*
12. *PGE 2020 (BART II)*
13. *Diversified Green with Wind in Wyoming*
14. *Diversified Thermal with Green, no Boardman Lease.*
15. *DEQ 2020* (Option 1) Similar to Portfolio 9, but with Boardman operating through 2020 and excluding Boardman BAL lease. We replace Boardman with a 441-MW CCCT in 2021. SCCTs are added in 2017 (51 MW) and 2019 (196 MW). A 4-year PPA is added in 2017 to balance capacity with other portfolios until a CCCT is added in 2021.
16. *DEQ 2018* (Option 2) Similar to Portfolio 9, but with Boardman operating through 2018 and excluding Boardman BAL lease. We replace Boardman with a 441-MW CCCT in 2019. SCCTs are added in 2017 (112 MW) and 2019 (136 MW).
17. *DEQ 2015* (Option 3) Similar to Portfolio 9, but with Boardman operating through late 2015/early 2016 and excluding Boardman BAL lease. We replace Boardman with a 441-MW CCCT in 2016. For modeling purposes, this additional CCCT acts as a proxy for a bridge PPA until construction of a replacement resource; however this modeling necessity does not reflect the execution risk of PPA availability and price discussed later in these Reply Comments. SCCTs are added in 2017 (51MW) and 2019 (196 MW).
18. *PGE 2020* (BART III) For generating resources, same resource mix as Portfolio 15 above.

f. The New Portfolio Analysis shows that PGE's 2020 Proposal is the Best Outcome for Customers

Using the methodology and metrics described in the IRP and Addendum we conducted a new portfolio analysis and have summarized the results below.

i. *Efficient Frontier Chart for all Portfolios*

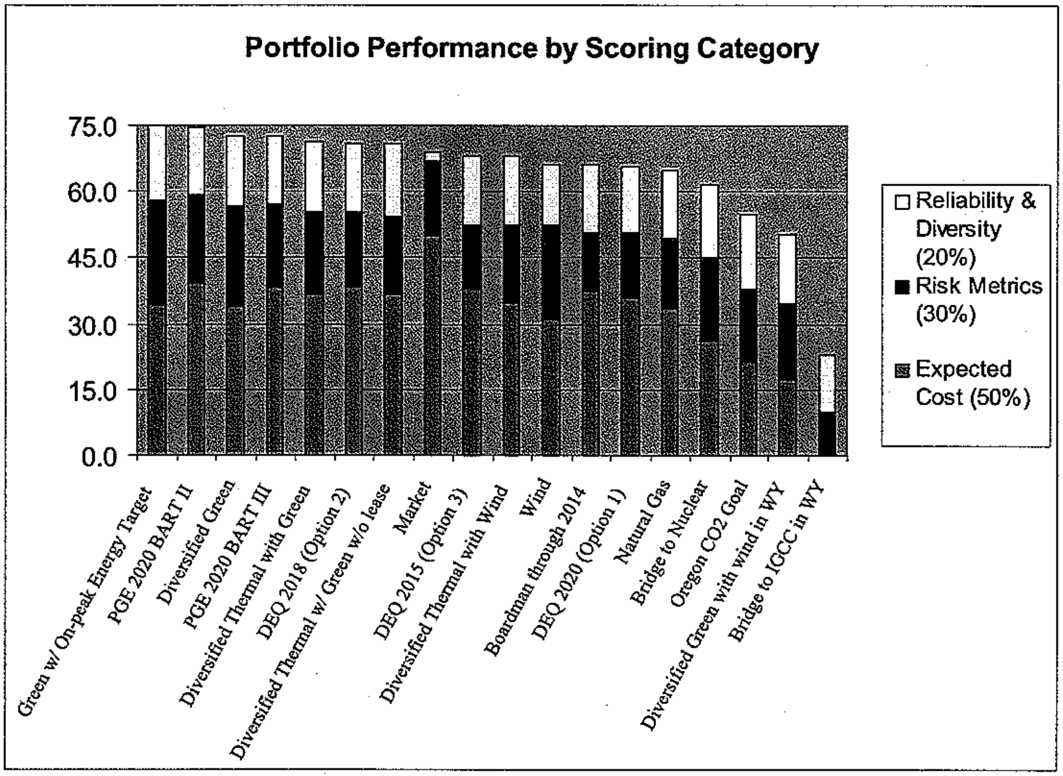
The chart below shows how the new portfolios we have added perform against the backdrop of the existing portfolios. This chart captures the chief cost and risk aspects of our deterministic cost and risk analysis and represents 70% of our overall portfolio scoring.



As shown in the Scenario Analysis figure above, PGE's BART II and BART III portfolios outperform all of the new DEQ options. It is *both* less costly *and* less risky than these options.

ii. Scoring Results for all Portfolios

Next we show our scoring graph for both the prior and new portfolios which incorporate the additional stochastic, reliability and diversity considerations. The full scoring grid is included as Attachment 3.



This table and the accompanying graph show how the portfolios perform in rank order and lead to the following observations:

First, new portfolios perform as we would expect them to given their characteristics as compared to the IRP Addendum candidate portfolios. That is, among early closure options, portfolios that keep Boardman open longer perform better, except for DEQ Option 1, which adds a very costly layer of additional controls.

Second, PGE's BART III proposal is a top-performing portfolio among Boardman early closure portfolios, just after our BART II proposal.

Third, the best performing BART I portfolios continue to be the best back-up plans if we are not able to obtain approval for BART III. For instance, Diversified Thermal with Green outperforms all of the DEQ options.

iii. Performance of New Portfolio Options Only

Finally, we isolate below the comparative controls cost and portfolio performance of the three new DEQ options and our BART III proposal, along with the BART II proposal submitted in our IRP Addendum which we retain for comparison purposes. The variable component of the operations and maintenance cost is based on an 85% capacity factor for the plant.

Controls Cost Summary and Performance	Controls/Closure Options*, $ Millions					
	PGE 2020 BART II (Addendum)	DEQ 2015 (DEQ Opt. 3)	DEQ 2018 (DEQ Opt. 2)	PGE 2020 BART III (Proposed)	DEQ 2020 (DEQ Opt. 1)	DEQ 2040 BART I
Overnight Nominal Capital Cost (100% share)	$ 41	$ 41	$ 75	$ 75	$ 343	$ 511
Inc. O&M per Year (Mostly Variable, 100%)	$ 8	$ 7	$ 23	$ 23	$ 16	$ 16
NPVRR cost vs. PGE 2020 BART II (PGE Share)	$ -	$ 150	$ 125	$ 103	$ 362	$ 278
Cost-only Ranking (50% of score)	1	4	3	2	6	5
Full Scoring Ranking	1	5	4	2	6	3

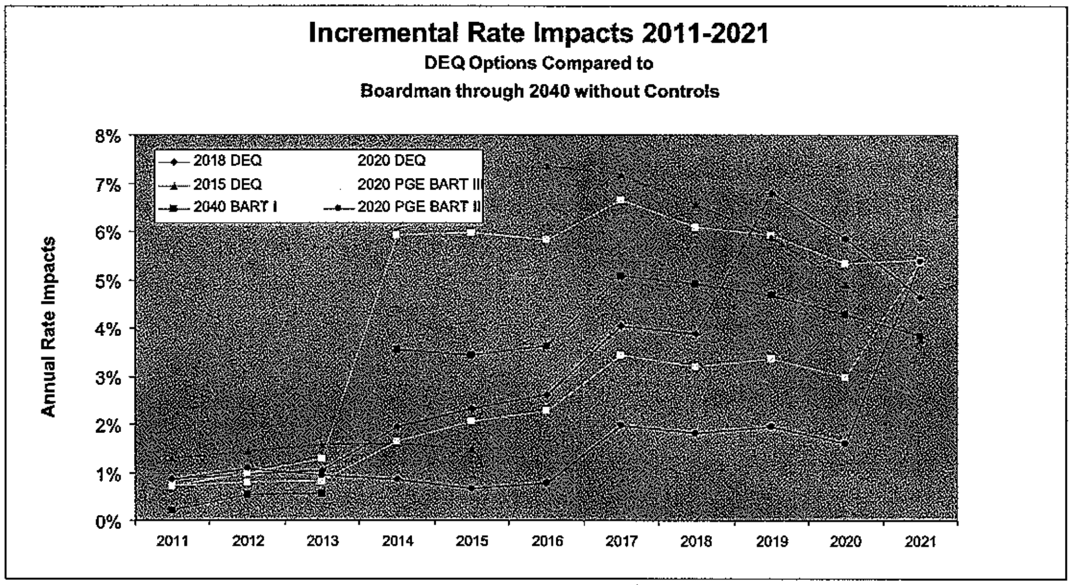
* Dates for IRP analysis purposes are at year-end.

** To be confirmed/adjusted based on 2011 testing. Must avoid triggering PM2.5 standard & avoid impacting mercury controls performance.
Note: DEQ 2040 (BART 1) is modeled in several IRP portfolios, this best-performing portfolio is Diversified Thermal with Green.

This table reinforces our finding that on both a cost and a combined cost and risk basis, PGE's BART III is the best proposal. The BART I proposal, based on the Diversified Thermal with Green portfolio, when including the risk considerations, is the most attractive and most viable back-up option. As stated at the start of this section, we also do not believe *any* of the new DEQ options can be implemented, for differing reasons, such as not being permittable, cost-effective or executable without an unacceptable and currently unknown level of risk.

g. <u>Rate Impacts</u>

Finally, while an IRP is not a ratemaking proceeding, rate impacts to our customers over the next decade clearly matter, particularly given the difficult economic climate in which we currently find ourselves. The following, which was earlier presented to the DEQ Fiscal Advisory Committee, shows how seemingly small differences in lifecycle net present value revenue requirements can magnify into fairly significant customer rate impacts between 2011 and 2021 as compared to Boardman through 2040 without BART Controls. It should also be noted that these rate impacts are strictly Boardman-related and ignore other rate impacts (fuel cost increases, other resource additions, RPS compliance, O&M, etc.) that would be in addition to those resulting from the Boardman actions.



Rate impact vs. 2040 without controls						
	Control/closure options					
	PGE 2020 (BART II)	DEQ 2015 (DEQ Opt. 3)	DEQ 2018 (DEQ Opt. 2) + testing	PGE 2020 BART III (Proposed)	DEQ 2020 (DEQ Opt. 1)	DEQ 2040 (BART 1)
Avg. Increase 2011-2021 (%)	**1.6%**	**3.9%**	**3.2%**	**2.4%**	**4.6%**	**3.2%**
Single Highest Year Increase (Year / %)	2021/ 5.4%	2016 / 7.4%	2019 / 6.8%	2021/ 5.4%	2017/ 6.7%	2017/ 5.1%
Cumulative Nominal Impact by 2021 ($Millions)	$345	$824	$677	$516	$958	$667

This life-cycle analysis includes the following:

- Revenue requirement (capital recovery, incremental fixed and variable O&M, incremental fuel cost differences due to heat rate / capacity changes) from new emissions controls, based on remaining life until closure year
- Revenue requirement (capital recovery, fixed O&M, fuel) for a replacement resource (likely), based on a 30-year book life
- Acceleration of current investment and capital additions of the Boardman plant from 2011 to the closure year
- Revenue requirements for all new plant additions should include salvage costs, property taxes, and a return based on current tax rates and PGE's regulated cost of capital

The table above shows the following impacts:

We show the average rate increase between 2011 and 2021, the latest year in which a replacement resource is placed in service for the early closure options. Given that these are equivalent to a permanent rate increase of the magnitude shown over an 11 year period, the increase percentages are not immaterial. Of these, the increase for BART III is the smallest for the options available to us. To put a finer point on impacts that are muted by averaging, we show the largest single rate increase and the year it takes place.

We also show near-term financial impacts in terms of additional cumulative costs to customers through 2021 compared to continuing to operate Boardman without additional controls except those required for mercury emissions. Note that these options range from a low of about $500 million incremental cost for PGE's BART III proposal to nearly $1 billion for DEQ Option 1. These are large amounts, and differences between PGE's BART III proposal and the DEQ options are significant. Additionally, it is noteworthy that based on a rate impacts view, BART I also outperforms the DEQ options and thus is the most attractive back-up option should we not receive EQC approval for BART III.

Because these rate impacts are driven by front-end revenue requirement loading from new controls and replacement resources combined with accelerated amortization of the existing Boardman investment, focusing on a 30-year levelized impact would not provide an accurate picture of impacts to customers in the near term. Hence, we have focused on those impacts that would occur over roughly the next decade, which is the same time period that changes to Boardman would be made under the PGE and DEQ proposals.

h. The Commission Should Acknowledge PGE's 2020 Proposal with a 2040 Backstop

PGE's new BART III proposal implements the more stringent reductions called for at a cost to our customers of $103 million above PGE's BART II proposal, while retaining the core objectives of reducing customer rate impacts and providing more time for a transition. We note that a broad spectrum of parties support a 2020 proposal including customer groups, and business, labor and community organizations. PGE requests that the Commission acknowledge its BART III proposal as being least cost and least risk and the best option for the company and its customers.

Should the EQC ultimately not accept our BART III proposal, then PGE requests that the Commission acknowledge the only remaining realistic and responsible proposal that the DEQ has allowed us -- installation of all BART and Reasonable Progress controls and operation of the plant on coal until 2040 or beyond.

i. Other Boardman Issues

We respond below to a number of other Boardman issues that were raised in Parties' initial comments.

i. Contingencies

The BART II proposal described in our IRP Addendum was subject to the resolution of the following three contingencies by March 31, 2011: approval by the EQC; reasonable assurance that Boardman will be subject to a legislative or regulatory resolution to MACT; and resolution of pending litigation. Some parties expressed concern with the timing of these contingencies. Sierra at 2; Staff at 1; CUB at 6-7. After considering the comments, we have determined that implementation of our new BART III proposal should be contingent only on EQC approval, by March 31, 2011, of a revised Oregon Regional Haze Plan based on our BART III proposal.[4] We recognize the risk remains that the outcome of either MACT or the pending litigation could require PGE to install controls at Boardman similar to those required to operate the plan through 2040 under the current Oregon Regional Haze Plan.[5] (BART I) As mentioned in our IRP Addendum, there is also a risk that DEQ may not issue a Title V permit that is consistent with its action on our BART III proposal in a timely manner, which could result in temporary closure of the plant until the permit is modified. IRP Addendum at note 12. We request that the Commission acknowledge that it is prudent for PGE to proceed with its 2020 proposal despite these risks.

ii. PGE Appropriately did not Speculate on other Uncertain Costs of Compliance

Sierra claims that the controls required by its lawsuit and MACT will be more expensive to install and operate than those controls analyzed in the IRP. Sierra at 29-31. The remedy of the ongoing lawsuit and outcome of the yet-to-be-conducted MACT rulemaking are purely speculative. Thus, PGE cannot determine which controls or emissions limits may be required, or when such requirements could become effective. Any analysis of costs or their impacts would also be purely speculative. PGE agrees however that the costs and risks associated with the pending litigation and potential MACT requirements are material risks to the implementation of PGE's 2020 proposal and requests acknowledgment upon full consideration by the Commission of these risks.

Sierra also claims that PGE has not analyzed the cost of compliance with new coal combustion waste rules. Sierra at Attachment 1, p. 32. With respect to potential regulation regarding coal combustion residuals (CCRs), PGE agrees with Sierra that "the costs associated with EPA's anticipated regulation of coal combustion wastes are uncertain." Sierra at Attachment 1, p. 33. To date, EPA has only issued a pre-

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[4] DEQ's website states that DEQ anticipates forwarding a final rule recommendation to the EQC in December 2010. See http://www.deq.state.or.us/aq/haze/shutdown.htm

[5] These risks are described in more detail at pages 122 and 123 of the IRP Addendum. Obviously these risks go away if PGE operates the plant to 2040.

publication version of proposed rules, which contains several regulatory options for CCRs. It is unknown whether such rules, if adopted, will pose a material cost or risk to PGE's 2020 Plan. PGE does not use wet impoundment of CCRs and sells the majority of its CCRs for beneficial use in other applications such as cement. Under all regulatory options being considered, the greatest regulation and cost risk is for wet impoundments, such as that used by Tennessee Valley Authority that resulted in the spill at its Kingston plant. *See*, Sierra at Attachment 1, p.34. Moreover, exemptions for beneficial use are being retained under all options presented by EPA. PGE believes at this time that incorporation of uncertain CCR costs and risks in its IRP analysis would not provide the Commission with further meaningful insight to evaluate the various scenarios.

iii. A Temporary Shut Down of Boardman Poses Significant Cost Risks for Our Customers

Staff states that it is evaluating potential bridging strategies allowing for the possibility of alternative timelines, beyond our investment deadline of March 31, 2011, to resolve the risks that we characterized in the IRP Addendum as contingencies. Staff at 1. CUB believes the 2014 and 2017 investments are not least cost/least risk and suggests that it is better to mothball the plant than to acknowledge the investments necessary for our back-up plan. CUB at 6-7. We want to be clear that if we do not make the March 31, 2011 scrubber investment, we will not be able to run the plant in 2014. We have described the cost variability and reliability risks which could result if we closed the plant and had to obtain roughly one-half of our electricity from market purchases. IRP Addendum at 124-125. Our analysis shows the incremental cost for replacement supply could be at least \$6.4 million per month under current conditions.[6] *Id.*

iv. PGE Appropriately Analyzed Replacement Costs of a CCCT and Renewables

Sierra's consultant states that PGE has not analyzed whether adding a new combined cycle natural gas-fired unit (CCCT) would be the lowest cost option if Boardman were retired at any time between 2014 and 2020. Sierra, Exhibit 1 at 13.

However, PGE did analyze whether a CCCT would be the lowest cost option in its responses to OPUC Data Requests 001 a & b (attached hereto as Attachment 4). In response to the requests, PGE modified (1) "Portfolio 10 – Boardman through 2014" by replacing the 441 MW CCCT in 2015 with the combination of a 221 MW share of a CCCT in 2015 and the remainder with wholesale market purchases; and (2) Portfolio 10 - Boardman through 2014" by replacing the 441 MW CCCT in 2015 with the combination

[6] The replacement power costs associated with recent Boardman outages underscores the cost variability risk posed by a mothballing strategy. In connection with a maintenance outage of Boardman in May 2009, through mid-August 2009 incremental replacement power costs were approximately \$4 million. In 2005/06 on the other hand we incurred approximately \$90 million for replacement power for outages occurring over an approximate 8 month period - almost \$400,000 per day of replacement power costs.

of a 221 MW share of a CCCT in 2015 and the remainder with additional wind resource in 2015. Both of these modifications resulted in higher cost, the first modification also resulted in higher risk.

In a related assertion, Sierra concludes that "[t]he fact is that rates will increase as a result of investments required to clean up or transition off Boardman. Sierra at 9. In transitioning off Boardman, however, PGE can step up its investment in conservation and renewables, options that will actually drive down ratepayers' monthly bills." With regard to the renewables portion of Sierra's statement, the portfolio results above show that additional renewables will have the opposite effect. In fact, this is compounded by the extremely capital-intensive nature of wind and most other renewable technologies. As further shown in Figure 11A-2 on page 53 of the IRP Addendum, predominantly green portfolios are not among the lowest cost portfolios.

v. PGE Considers the Appropriate Boardman Capacity Factor in its IRP Analysis

Sierra states that PGE's analyses show that by 2020 Boardman will no longer be baseload even if $510 million is invested in environmental upgrades.

While it is true that by 2020, PGE's reference case shows Boardman operating at a 44% capacity factor, this lower dispatch is included in the economics. In other words, the cost of the environmental upgrades along with the lower capacity factor is inherent in the NPVRR calculation.

While running less based on a \$30 CO_2 price, Boardman continues to provide valuable seasonal supply during the highest load months of the year. In addition, operating Boardman through 2040 preserves important optionality. If carbon compliance costs are less than anticipated, Boardman will continue to provide valuable baseload generation, running at close to 60% in 2020 in both the \$12 and \$20 CO_2 cases. This compares to an average capacity factor of roughly 76% for Boardman over the last 3 years (2007-2009), 68% for Coyote Springs for that period, and 73% for Port Westward in 2008/2009. Even if carbon costs are $65, Boardman operates at about 20% in 2020 and still continues to provide capacity through 2040.

PGE has appropriately considered federal carbon legislation in its modeling. Even with the required environmental upgrades, the plant runs less over time due to potential carbon costs but is still a viable (and valuable) resource through 2040.

3. Cascade Crossing

In written comments and at the June 7, 2010 Commission workshop, parties raised the following issues with respect to the Cascade Crossing transmission project: (i) the need for the Cascade Crossing transmission project both generally and in the event that PGE ceases coal-fired operations at Boardman; (ii) the economics of Cascade Crossing compared to BPA transmission; (iii) PGE's experience with similar projects;

(iv) potential Willamette Valley upgrades; and (v) the milestones for the project. We address these issues below.

a. Cascade Crossing Can Provide Much Needed Transmission Capacity and Other Benefits to PGE's Customers

As discussed in our 2009 IRP, very few new transmission facilities have been built in the Western Interconnection over the last two decades. Load growth and the surge in the development of wind generators over that same period have nearly exhausted any excess transmission capability, such that the existing transmission system has become increasingly constrained. The situation is becoming critical. As a recent *Oregonian* article noted "the pace and geographic concentration of wind development, coupled with wild swings in its output, are overwhelming the region's electrical grid and outstripping its ability to use the power or send it elsewhere." Ted Sickinger, *Too much of a good thing: Growth in wind power makes life difficult for grid managers,* Oregonian, July 17, 2010. In an IRP Order issued in 2004, the Commission recognized that additional transmission capacity would be needed to support the acquisition and development of renewable resources and specifically directed PGE to "work with BPA and others to develop transmission capacity over the Cascades." Order No. 04-375 at 12. Since the issuance of the 2004 IRP Order, PGE has acquired additional transmission rights from BPA. But we have found that such transmission is at risk for an increasing number of curtailments, as well as potential increases in rates for integrating wind resources.

Moreover, while PGE's need for additional transmission to access resources on the eastern side of the Cascade Mountains has grown, BPA has virtually no available long-term firm transmission posted on its OASIS that would allow PGE to access such resources. PGE has spent several years studying the potential of the Cascade Crossing transmission project and believes that it can bring significant benefits to its customers and to the region including:

- improved reliability due to the significant increase in transfer capability on the Cross-Cascades South and BPA's West of Slatt cutplanes and the reduced stress on the BPA I-5 corridor cutplanes;
- the ability to directly connect existing and new generating resources into PGE's system;
- greater access to wholesale energy markets;
- greater access to renewable generation in locations that have the potential to diversify our renewable generation profile;
- the potential for reduced curtailments in wind generation due to the ability to integrate wind generating resources into PGE's balancing authority, rather than through BPA;
- improved viability of new renewable resources that are currently without access to transmission facilities;
- decreased energy line losses;
- the ability to bring additional contingency reserves to PGE's system; and

- reduced exposure to future BPA transmission and wind integration rate increases.

Cascade Crossing will primarily parallel existing rights of way and is the only new line currently being proposed in the region that will provide transmission capacity across the Cascades[7].

The need for Cascade Crossing and its benefits are evidenced by PGE's receipt of requests to interconnect 2292.4 MW of winter generating capacity to Cascade Crossing[8]. Almost half of that capacity (approximately 1220 MW) is from third-parties. The approximately 2300 MW of interconnection requests far exceeds the 1500 MW of capacity that a single-circuit facility would provide, making it apparent that the prudent course of action is for PGE to proceed with development of the double-circuit configuration.

b. Early Termination of Coal-fired Operations at Boardman will not affect the Need for Cascade Crossing

An early closure of Boardman is unlikely to affect the need for Cascade Crossing. The Boardman site has significant value for locating a new generation facility. Specifically, the site has ready access to existing transmission facilities, natural gas supply, water for cooling, and land. As evidenced by the 1200 MW of wind generation currently in PGE's interconnection queue, Cascade Crossing will also span extensive wind-rich areas and can provide transmission access to sites that are particularly attractive for wind development. Therefore, if the existing Boardman plant were to close early, it is likely that a replacement facility would be developed on the Boardman site and/or on a site that would use Cascade Crossing to meet its transmission needs.

Moreover, even if additional generation were not developed on the Boardman site, an early closure of Boardman would only eliminate 17% of the approximately 2300 MW of interconnection requests currently in PGE's queue -- PGE would still need to construct a line capable of transmitting 1907 MW to satisfy the remaining pending interconnection requests in PGE's queue.

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[7] BPA's John Day to McNary upgrade referenced by some parties stops in John Day, Oregon and does not cross the Cascade Mountains to serve the load centers on the western side of the state.

[8] Under the Federal Energy Regulatory Commission regulations governing interconnection and transmission requests, anyone submitting an interconnection request is required to pay a deposit of $10,000, which is used by PGE to study the feasibility of accommodating such request. An Interconnection Customer is not actually committed to interconnect to the Project until they sign the applicable Large or Small Generator Interconnection Agreement with PGE, and cannot actually acquire transmission service for the output of their plant unless they submit a transmission service request and sign a transmission service agreement with PGE.

c. Cascade Crossing is a Better Economic Option for our Customers than BPA Transmission

In Chapter 8 of the 2009 IRP, PGE conducted an economic analysis comparing transmission service from BPA under BPA tariff rates versus transmission service on Cascade Crossing. Our analysis demonstrates that, for a reasonable range of assumptions of BPA tariff rates, generation interconnection requests, and participation by third parties in the project, Cascade Crossing is the better economic option for PGE's customers. The economic considerations are even more compelling given that PGE used conservative estimates in conducting its analysis. For example, we made the conservative assumption that BPA transmission would be available at BPA embedded rates rather than at incremental rates, and that PGE would fund, up-front, the Cascade Crossing project costs even if some of those costs could be assigned to other transmission customers under our OATT. In addition, our estimates include a contingency of $80 million or 9.96% for the double-circuit project costs, i.e., two sets of conductors utilizing common transmission towers. Finally, the economic analysis did not include any of the non-quantifiable benefits resulting from improved reliability and access to renewable generation that we identify above. In short, even conservative assumptions show that construction of Cascade Crossing is a better, more economic choice for our customers than using BPA transmission.

d. PGE Has Significant Experience Managing Large Energy Projects

CUB questions whether PGE has sufficient experience managing transmission projects. These concerns ignore PGE recent experience managing major energy projects with significant transmission components. For example, PGE managed the development, permitting, engineering, procurement, and construction of Coyote Springs, Port Westward, and Biglow Canyon. The Port Westward project included 20 miles of 230 kV line. All three of these projects came in on-time and on or under budget.[9] In addition, in a typical year, PGE manages a capital budget of about $230 to $280 million. These include additions to PGE's transmission and distribution system and substations and additions and improvements to PGE's generating plants. The company has significant experience in the contracting and management of these projects. PGE will employ proven techniques that are common to the industry, that are used to manage project scope, budget and schedule, and that PGE has used successfully in past projects.

e. The Potential Costs of the Willamette Valley Upgrades are Included in the Estimated Project Costs but PGE has not yet determined whether the Upgrades are Necessary

Willard believes that PGE's economic analysis should have taken into account the costs for a new line from Salem to Oregon City (referred to as the "Willamette Valley Upgrades"). PGE's economic analysis did in fact consider the potential costs of the Willamette Valley Upgrades. The costs included $46 million for the Willamette Valley Upgrades. However, PGE has not yet determined whether Willamette Valley Upgrades

[9] Biglow Canyon Phase 3 is not yet completed, but is expected to be completed on-time and on-budget.

will be needed as part of Cascade Crossing and is not asking the Commission to acknowledge them as part of Cascade Crossing.

f. Cascade Crossing Milestones

Both in filed comments and remarks made at the Commission workshop, several Parties asked PGE to provide additional clarity with regard to our milestones for proceeding with Cascade Crossing.

The milestones provided in Chapter 8 of the IRP are as follows: (1) path rating; (2) estimated project costs; (3) amount of interconnection/ transmission capacity needed for PGE resources; (4) amount of equity participation; and (5) expected cost of BPA transmission.

We ran five economic cases based on these factors to illustrate a range of potential economic outcomes comparing Cascade Crossing and use of BPA transmission. IRP at 192-199. Cases 4 and 5 show a positive Net Present Value (NPV) for the double circuit configuration, when comparing the expected benefits and costs of Cascade Crossing versus continued reliance on BPA transmission services. Both cases assume the following milestones are met:

- a path rating of 2200 MW;
- estimated project costs of $823 million;
- 1900 MW of interconnection/transmission capacity for PGE resources;
- partnership with a third-party for the segment between the Boardman and Coyote Springs plants;
- partnership with one or more other transmission providers for the Coyote Springs substation; and
- equity participation for at least 300 MW of transfer capability.

Case 4 assumes that BPA's transmission rate increases at an average nominal rate of 4.0% from 2011 to 2025, after which the growth rate decreases to 3.2%, with a one-time increase in rates of 10% in 2015. Case 5 assumes that after 2025 BPA's transmission rate increases at a nominal 3.5% per year.

The key factors used in our economic analysis interact such that any change in one factor cannot be considered without also looking at changes in the other factors. For example, a 5% increase in the final project costs by itself might indicate that it is not economic for the project to go forward. However, if the project costs increased by 5% *and* the path rating increased by 15%, then a decision based on the combination of the two factors might suggest otherwise. A Net Present Value analysis such as that used in the IRP allows us to consider the interaction of all major drivers of value in the economics of the project. Moreover, any decision to proceed must also consider the non-quantitative benefits discussed previously in this section.

Currently, the economic analysis appears favorable for proceeding with the project. We have completed Phase I of the WECC Path Rating process for the original *single*-circuit configuration, which resulted in a proposed rating of 1500 MW East to West (E-W) in the winter and 1475 MW E-W in the summer for delivery into Bethel substation. We continue to study the double-circuit configuration and we expect to complete the WECC Phase I process for the double-circuit configuration by year-end 2010. Our preliminary results show that we're on target to achieve a proposed rating of at least 2200 MW. PGE's cost estimates continue to be well within our contingency range. We have also signed a Memorandum of Understanding (MOU) with PacifiCorp to engage in negotiations toward definitive agreements related to jointly developing and constructing Cascade Crossing. The agreements would provide PacifiCorp with up to 600 MW of bi-directional transmission capacity on the line and potentially an additional 200 MW of capacity into central Oregon. PGE has also entered into an MOU with Idaho Power Company (IPC) which provides for IPC and PGE to cooperate on development of transmission in the Boardman area. In addition, we are in active discussions with counterparties for partnerships for the Boardman to Coyote Springs segment and the Coyote Springs substation. We continue to believe that our assumptions with regard to BPA rate increases are reasonable. As discussed above, PGE's generation interconnection queue currently has requests for approximately 2300 MW of capacity. PGE will provide an update of the milestones in its annual update of the 2009 IRP and in its next IRP.

In short, the Cascade Crossing line offers a number of benefits to PGE and its customers by providing an economic means for PGE to access new and existing generation on the eastern side of the Cascades, including renewables required to meet future RPS targets, and by improving reliability of the regional transmission system. We ask that the Commission acknowledge that it is prudent for PGE to proceed with the development of the double-circuit configuration.

4. Resource Needs

A. Load Forecast

Several parties (Sierra, NWEC, Willard, Ecumenical Ministries) raise concerns regarding PGE's forecasted load growth. These comments miss the mark for three fundamental reasons. First, they focus unduly on the low growth over the last recession-filled decade without considering long-term economic and load data. Second, they are based on regional load data that include areas with different growth characteristics than PGE's largely urban service territory. Finally, a significant portion of the resource needs identified in the IRP are driven by the retirement or expiration of existing resources. As a result, a substantial need for new resources exists aside from any needs driven by future load growth. We address each of these shortcomings in more detail below.

i. PGE's Load Forecast Appropriately Considers Long-Term Economic and Load Data

Sierra, NWEC, and Willard's criticism of PGE's load forecast focuses unduly on PGE's load growth history over the last decade. There are serious flaws with basing forecast assumptions on data from the 1999 – 2008 timeframe. Namely, extrapolations from the most recent decade would forecast an extension or repeat of the period's historically atypical economic environment, including the 2008 financial crisis deemed by former Federal Reserve Chairman Greenspan as a "once in a century" crisis. It would forecast that the United States and Oregon economies will remain mired in an economic slump for the next 10 – 30 years. This is an unlikely future outcome and not predicted by most economic forecasters.

A repeat of the most recent decade is, we believe, unlikely for a variety of reasons. First, the decade from 1999 through 2008 was exceptional in terms of poor economic performance. The United States generally, and Oregon in particular, experienced two of the most protracted and deepest economic recessions since the Great Depression. This period has been portrayed in the media as the United States' lost decade. Employment for both the United States and Oregon remained essentially flat between 2000 and 2009 as job gains made after the 2001 recession were wiped out by huge job losses in 2008 and 2009. The job losses totaled almost 8.4 million jobs for the US and nearly 150 thousand jobs for Oregon from peak (December 2007) to trough (December 2009) -- the most since the Great Depression. Oregon Department of Employment and United States Bureau of Labor.

In the preceding three decades, the United States and Oregon encountered just one recession each decade: the First Oil Embargo (1973) in the1970s, the early-1980s following the Second Oil Embargo, and the Gulf-War recession (1991) in the 1990s. Both the United States and Oregon, however, endured not one but two deep recessions as the last decade of the 21st century unfolded: the 2001 recession, worsened by a global "tech wreck" that lasted through 2003 in Oregon, and the Great Recession of 2008 driven by the financial crisis lasted through 2009 and is still lingering in 2010. In addition, Oregon (and the West coast) was also hit by the 2000-2001 energy crisis that in PGE's case prompted curtailment, demand buyback (~28 MWa) and conservation programs (~21 MWa). The last decade also saw several one-time reductions in load and changes to PGE's territory. For example, PGE sold part of its service area to Columbia River People's Utility District (PUD) and Clatskanie PUD and also lost industrial loads due to self-generation, or reduction in operations by individual customers. These losses in aggregate are roughly 140 MWa. Such non-recurring events should not be included in future growth expectations unless they are anticipated to continue or occur again.

Moreover, extrapolating the experience of the most-recent decade to the next is often erroneous. To postulate that the Oregon's economy and PGE's energy delivery will repeat the experience of the early 2000s for the next ten to thirty years is to assume that the economy will remain in perpetual stasis for the duration. While certainly possible, longer-term history argues against it.

Citing the Commission's *2008 Oregon Utility Statistics,* Sierra's consultant states that PGE experienced "a total growth in energy load of less than four percent during the entire nine year period..." Sierra at 15-16. Although these statistics point out that the time period was challenging for the Company and the local economy; basing a forecast on these statistics alone would not be prudent. For example, while the annual energy sold for the entire state of Oregon declined by 263,074 MWh over the same time frame, for a growth rate of roughly negative one percent, it is unreasonable to conclude that Oregon as a whole will experience declining electricity use for the next 30 years.

In short, focusing only on PGE's load growth history over the last decade is not a sound basis for forecasting future results.

ii. PGE's Load Forecast Focuses on PGE's Service Territory, Not Regional Forecasts for Areas with Substantially Different Load Characteristics

Some commenting parties compare PGE's load forecast unfavorably to the Northwest Power and Conservation Council's (NWPCC) Draft Sixth Plan load forecast. This comparison is founded on the faulty premise that an individual utility's forecast cannot exhibit any material differences from the NWPCC Regional Forecast. The premise improperly assumes that the NWPCC Region is one large, mostly homogenous region economically and demographically. This is not unlike concluding that, because the NWPCC has determined that the region as a whole maintains more generation than its load requirement, that each individual load serving entity must also have a surplus of generation.

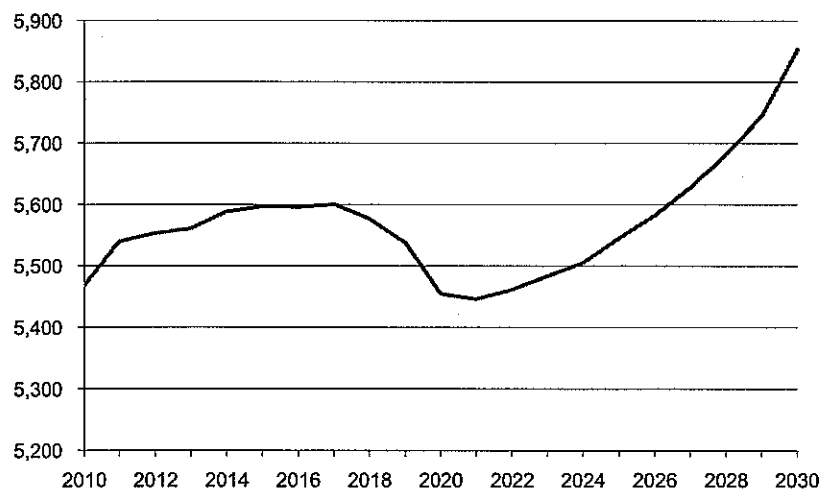
PGE's forecast is based on its service area, which is predominantly urban and dominated by high technology customers. The NWPCC Forecast covers the four-state area encompassing Idaho, Montana, Washington, and Oregon, which includes many slower-growing rural areas. Historically, PGE's actual load growth has been higher than the area covered by the NWPCC Forecast. For example, for the period 1986 - 2005 the NWPCC regional area electricity delivery grew 0.6% annually and Oregon's delivery grew 1.3% (based on available data provided by NWPCC), while PGE's energy delivery rose 1.8%. PGE's load forecast is not and should not be identical to the NWPCC Forecast.

As we discuss in more detail in the 2009 IRP, when accounting for regional differences, PGE's forecast is largely consistent with the NWPCC Forecast. IRP at 37. For the 2010-2015 time period, PGE's annual average load growth rate is 1.7% (including embedded EE) while the NWPCC's load growth forecast for Oregon is 2.0%. *Id.* Separately, we have since calculated that the 2010-2021 timeframe has annual load growth of 1.8% versus 1.5% for PGE and the NWPCC respectively.

It is in the out years – outside the Action Plan horizon – where the differences are larger. These differences in turn are at least partially driven by energy efficiency (EE) assumption differences that do not affect resource decisions during the Action Plan horizon.

We believe NWPCC's EE assumptions for the period outside the Action Plan horizon are unrealistic. The figure below shows the NWPCC's forecast for Oregon after inclusion of conservation for the period 2010-2030. They show total energy use that increases, stabilizes, declines, and then increases again. It is evident that the NWPCC expects a large amount of conservation starting around 2017. In fact, the NWPCC assumes that conservation will swamp load growth leading to declining energy use for a period of 3-4 years when their EE forecast is taken into account.

NWPCC Energy Forecast for Oregon after Conservation



Our forecasts – relying on the Energy Trust of Oregon (ETO) – do not show conservation that is in excess of load growth. It would be hard to imagine a scenario with declining loads outside of a sustained recession. Most important, this decline in load, which the NWPCC forecasts and we do not, is outside of the Action Plan horizon and will not affect resource decisions for which we seek acknowledgement.

PGE's non-EE adjusted load forecast base case has an annual average growth rate of 1.9%. This is consistent with historic load growth. See Attachment 5, PGE Response to OPUC DR 054. Eleven of the last twenty-eight years exhibited growth rates of 2.7% or higher. When compared to the 1.9% growth rate used in the 2009 IRP, sixteen years - more than half - were at or above the 1.9% mark. This historic data was not adjusted for the transfer of portions of PGE's service area to public utility districts in 1985 and 2001. If adjusted for the reduction in PGE's service territory, the historical growth rates would be even higher.

iii. PGE's Resource Needs, Particularly Capacity Requirements, Do Not Rely on Load Growth Forecasts Alone.

Disputes regarding load growth can serve to obscure other reasons for new resources. PGE's need for new resources is also driven by the need to replace expiring supply sources, particularly for capacity resources, where contract expirations are the dominant driver. Over the planning horizon PGE will lose approximately 1,000 MW of capacity contracts. Conversely the peak load growth for 2010-2015 is projected at 274 MW. Accordingly, contract expiration, not load growth, is the primary driver of the need for capacity resources.

Expiring resources are also a significant driver to the need for new, future energy resources. We are losing approximately 300 MWa of energy resources during the Action Plan horizon. IRP Table 2-1. For the same time period, 2010-2015 load growth is approximately 213 MWa. It is the combination of both expiring existing resources and load growth that drives the need for significant new energy resources.

iv. Miscellaneous Other Load Comments

NWEC cites a letter submitted to the Commission by a member of Willard comparing PacifiCorp's 2008 IRP load forecasts to PGE's load forecast. Such a comparison is inappropriate. The two utilities serve different geographic areas and have a significantly different customer base.

Willard draws speculative conclusions from anecdotal all-time peak records. It correctly points out that PGE's all-time winter peak of 4,073 MW was set in 1998. This peak occurred under a one-in-ten condition (average 19.5 degrees) and before PGE sold portions of its northern-most service area to the Clatskanie and Columbia River Public Utility Districts. Our more recent winter peak of 4,031 MW occurred under a considerably less stringent one-in-three weather condition (average 25 degrees). In addition, PGE continues to set summer peak records due to a rapid increase in air conditioning penetration over the last decade (most recently 3,949 MW). We do not believe that a one-in-ten winter event from 1998 indicates that PGE's load is not growing. It is very likely that we would set a new all-time peak today given similar weather conditions to 1998.

Sierra points out that PGE's load forecasts have decreased since the IRP was filed, Sierra at 18. However, these changes are not material to the Action Plan. The drop in forecast energy is due to both the additional conservation being included in the load forecast and the temporary loss of industrial load. We forecast loads for larger industrial customers individually. We expect curtailed industrial loads to return once the economy rebounds. For 2014 the net reduction in the load forecast after accounting for EE and curtailed industrial load is approximately 50 MWa -- about a year's worth of load growth.

B. Energy Efficiency

Parties raise several issues around the amount of EE included in PGE's 2009 IRP. Sierra's consultant and NWEC suggest that PGE has overlooked additional EE in its portfolios. Sierra at 17, NWEC at 7. However, both parties apparently ignore the fact that PGE has incorporated **all** cost-effective EE as forecasted by the ETO. Neither party offers evidence to indicate that additional EE will be available, much less cost effective. The ETO is an independent third party established by the Oregon Legislature with a mandate to use funds collected by PGE to expand the use of energy efficiency and renewable resources. PGE used ETO's energy efficiency forecasts in the 2009 IRP and no party has presented any evidence that the ETO forecast is faulty and that PGE should not rely upon it.

PGE has been at the forefront of developing EE as a resource. 2009 IRP at Chapter 4. In fact, in 2008 the Commission approved our request to collect an additional 1.25% in public purpose charges to develop additional cost-effective EE. *See,* OPUC Staff Report, Item No. 2 (May 20, 2008). The additional EE was based on the ETO study that provided the basis for our 2007 IRP. The Commission approved an additional funding increase at the May 25, 2010 Public Meeting. The Staff memo recommending approval of this increase reviewed PGE's EE targets and concluded that they were "reasonable."[10] If we (or the ETO) believed there was additional cost effective EE available, it would be incorporated in our IRP modeling.

NWEC points out that EE is worth more than its avoided cost due to optionality considerations. NWEC at 12. However, it fails to mention that the ETO study does indeed value EE at a higher rate than PGE's avoided cost. EE is valued at 110% of the cost of a CCCT.

Many intervenors assert that PGE's EE forecast does not match that of the NWPCC Forecast. Exact comparisons with the NWPCC Forecast are difficult. As discussed in the Load Forecast section, the NWPCC uses an aggregate forecast for the entire region and does not provide forecasts for individual companies, or even urban versus rural break-outs. That said, PGE's EE values are reasonably close to the NWPCC Forecast. 2009 IRP at 57.

Through 2017, PGE's IRP and the NWPCC Sixth Plan basically have a similar amount of EE (or conservation) as a percent of load growth, as shown in the table below. The values begin to diverge in 2017 due to the NWPCC's inclusion of potential emerging technologies which ETO did not include. The ETO, by contrast, relied on proven programs and technologies and did not engage in speculation regarding future EE savings that are not currently commercialized or cost effective. In any case, the point of divergence is outside of the Action Plan horizon and would have a minimal impact on this IRP Action Plan.

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[10] "While these targets have not been acknowledged by the Commission through the IRP process, Staff is confident that the targets are reasonable." *See,* OPUC Staff Report, Item No. CA 16 (May 25, 2010)

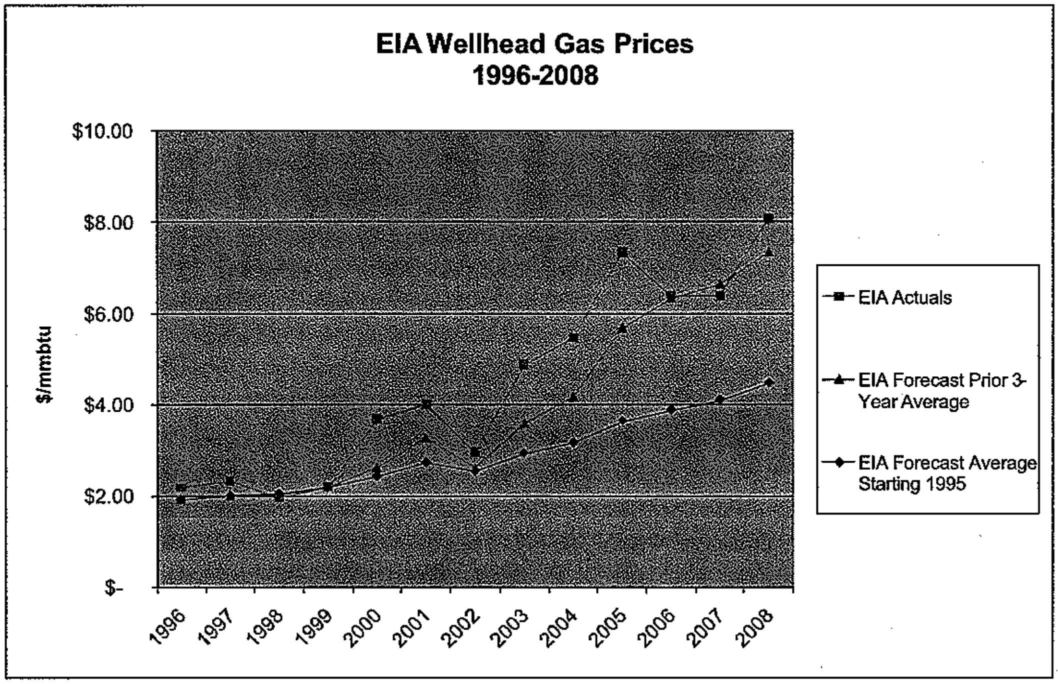
Year	Percent of Council's Oregon Load met with Conservation	Percent of PGE Load met with EE
2010	2.3%	2.0%
2011	3.3%	3.1%
2012	4.4%	4.2%
2013	5.6%	5.5%
2014	6.8%	6.6%
2015	7.9%	7.8%
2016	9.0%	8.8%
2017	10.1%	9.7%

5. Fuels Forecasts

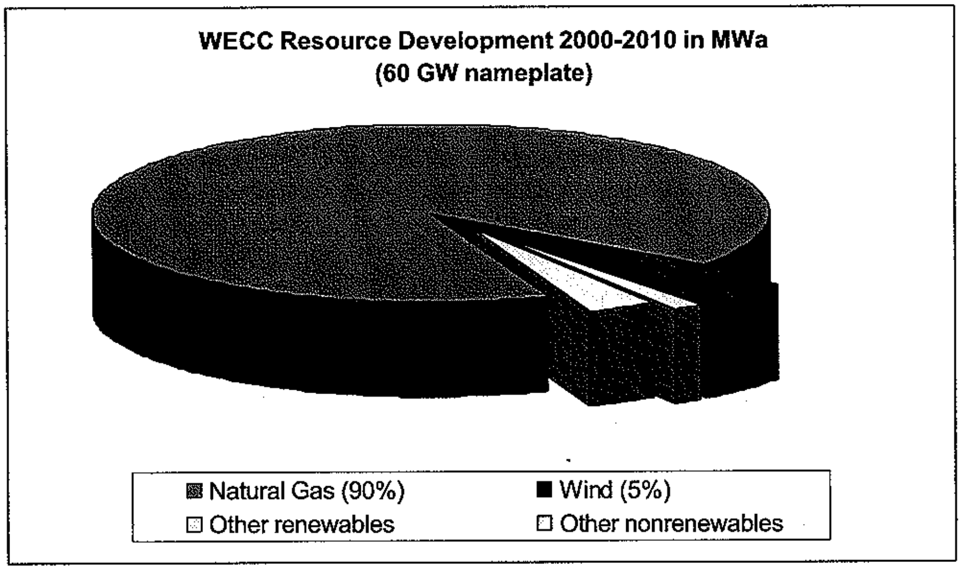
A. Natural Gas

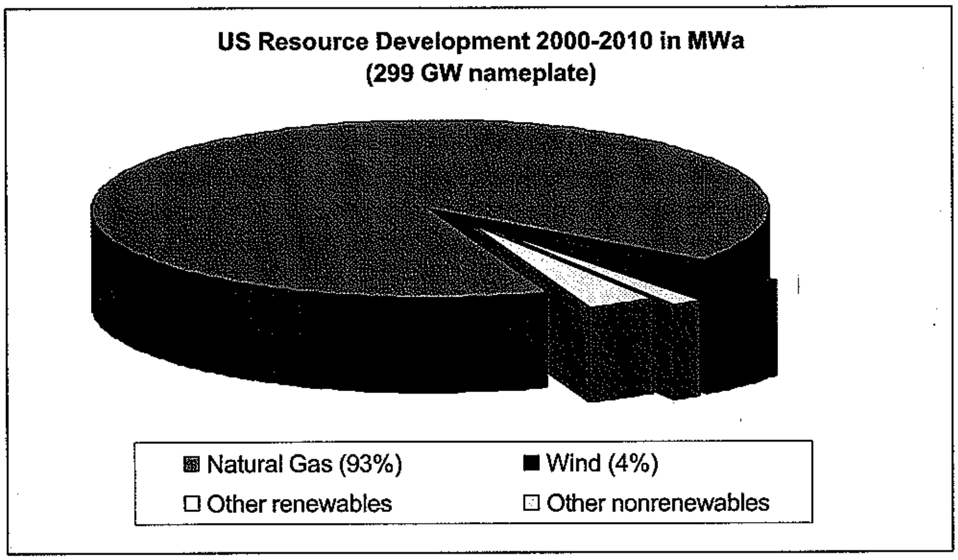
Some intervenors and Staff commented that the gas price forecast used in PGE's 2009 IRP was too high compared to more recent forecasts that have since been released. Sierra, Exhibit 1 at 4, NWEC at 18, Staff at 2, The 2009 IRP natural gas forecast is based on the August 2009 PIRA Energy Group, Inc. (PIRA) forecast for Henry Hub (with basis adders for AECO, Sumas, and other hubs), which was the most recent forecast at the time that PGE filed its 2009 IRP on November 5, 2009. Gas price forecasts released in mid-April show a decrease in gas prices. We recognize that gas price forecasts, like gas prices themselves, change over time and those changes can be dramatic. In the span of roughly a decade we have seen long-term gas forecasts swing from relatively inexpensive to very expensive and back resulting in the high price volatility recognized in the natural gas market. Each of these changes in the long-term forecasts was based on fundamentals research and information about future domestic supply and demand. However, each time we have seen a forecast for tight or abundant gas supply, the forecast has been proven incorrect within a few years. We therefore must be careful to avoid making long-term planning decisions based on a gas forecast of either "cheap and abundant forever" or "scarce and expensive forever." History has shown that inevitably new facts and information eventually emerge driving supply and demand to find a new equilibrium that can cause both the future outlook and current gas prices to change. This innate price volatility also underscores why increasing gas concentration for electric generation magnifies price risk for our customers and earnings risk for our shareholders.

Sierra's comments rely on forecast gas prices from the federal Energy Information Administration (EIA). Sierra, Exhibit 1 at 4. An informal PGE review of EIA forecast versus subsequent actual prices shows that EIA natural gas forecasts have historically tended to under-estimate actual prices. EIA has under-forecast gas prices by about 27% of actuals when considering the average forecast since 1995, and 12% below actuals when considering the forecasts for the applicable year made in each of the three prior years (for example, for actual 2000 natural gas prices, we compared forecasts from 1997, 1998, and 1999). The disparity in the forecasts is shown in the following figure:



In addition, several factors may well serve to put upward pressure on natural gas prices. For example, current gas prices do not account for the potential curtailment of a substantial portion of the less efficient portions of the coal fleet due to expected carbon regulation. This will likely result in a large, sustained increase in gas demand and associated need for new pipeline infrastructure. To illustrate this point, refer to the graph below which was adapted from a Ventyx chart included in an April 2010 NWPCC Resource Adequacy Technical Committee presentation. The graph shows the resource mix added in California alone during the last decade, where 95% of new generating resources are gas-fueled (the remaining 5% being a mix of renewables). While not shown here, we note that trends in the U.S. as a whole are similar.





In addition, an increased spread between oil and gas prices will cause users that can switch fuels to substitute gas for oil, which will result in upward pressure on gas demand. In short, price disparities tend to self-correct over time as demand increases to meet supply.

Moreover, new potential supply sources face an uncertain future. Unconventional domestic gas supplies such as shale and tight sand formations have been the primary driver in the increase in gas supplies and the outlook for decreased gas prices. While shale gas appears to be abundant, at this point in time it is still not well understood whether these new supplies are sustainable over the next few decades, what the longer-term environmental impact is to both fresh water supply and to groundwater, or the extent of any price impacts which might arise from increased regulation of the relatively new horizontal drilling and "fracturing" methods used to reach these new supplies.

Environmental organizations are already calling for increased regulation of these extraction techniques – the "robust and effective regulatory structure" for which Sierra and others advocate. *See,* Sierra at Exhibit 1, p. 10. The recent Gulf-BP oil spill has also increased public demands for increased regulation and potential curtailments of all types of oil and gas drilling. Increasing regulatory scrutiny and the potential for higher compliance costs associated with non-conventional gas supply drilling has received considerable media coverage suggesting that increasing regulation and compliance costs for unconventional natural gas extraction are likely in the future. *See, e.g.* Jeff Brady, *Face-Off Over 'Fracking': Water Battle Grows on Hill,* NPR, May 27, 2009, http://www.npr.org/templates/story/story.php?storyId=104565793, and Christopher Helman, *Gas Industry Faces the Dangers of Fracking,* Forbes, Sept. 28, 2009, http://www.forbes.com/2009/09/28/cabot-hydraulic-fracturing-business-energy-fracking.html.

Finally, in the context of this IRP, gas price risk is highly asymmetric in at least two unfavorable ways. First, there is a clear limit to how low natural gas prices can go, namely the cost of extraction and transportation. Current forecasts therefore have little downside risk since prices are relatively low today and price reductions cannot exceed the price floor set by extraction and transportation costs. Second, PGE's increasing reliance on natural gas serves to amplify its exposure to the risk of higher-than-forecast gas prices. In particular, in the case of a 2015 Boardman closure, approximately 55% of our *energy* resource mix would consist of natural gas, while generally holding our Beaver CCCT plant in reserve for capacity needs. PGE's exposure to higher than forecasted gas prices would become substantial. Accordingly, we believe that the Commission should be cautious about allowing the current optimism in gas projections to unduly influence our approach to resource decision-making.

Sierra's comments include several confidential figures which appear to be defective. Figures 1 through 5 included in Sierra's comments include some information that is not recognizable by PGE. These do not appear to represent the prices included in our IRP. Because the figures are not descriptive of what is represented (for example, real or nominal levelization, over what time period, representing what hub, and using what near-term forecast) PGE is unable to replicate some of these figures. For example, in looking at the year-to-year price shape in Sierra Comments, Exhibit 1, Figure 2, we find that it does not resemble the shape reported in IRP Figure 5-1 on page 77, even when converted to 2009$. This also does not represent the shape provided by PIRA for Henry Hub. PGE submitted a data request to Sierra requesting its gas price forecasts in an attempt to reconcile the discrepancy. *See,* PGE Data Request 21 dated May 17, 2010, attached hereto as Attachment 6. However, in answering that data request, Sierra simply referred back to Figures 1 through 5 above but did not provide annual gas price forecasts.

B. Coal

Sierra's consultant suggests that PGE failed to model the potential for higher coal prices in any of its future scenarios. Sierra, Exhibit 1 at 26. In fact, PGE has incorporated large increases in its delivered coal price forecast as part of its reference case assumptions. Overall, PGE has assumed a real increase in delivered coal prices (which includes the coal commodity and transportation costs) of 85% between 2008 and 2014, with a 41% increase between 2013 and 2014 alone.

The 2009 IRP used both the PIRA and EIA coal commodity forecasts. PIRA forecasted an average real increase of 8% for 2010 and 2011, while EIA forecasted an average real increase of 1% for 2010 and 2011. For 2012, PIRA forecasted a real increase of only 0.1% and EIA forecasted a real increase of less than 2% for 2012. This resulted in a real 6% increase from 2010 to 2012 when averaging the two commodity sources.

Recent forecasts of coal prices have been equivocal and do not warrant a change in the coal price forecast. EIA has decreased its commodity forecast for PRB low-sulfur coal from last year. For the period 2010 through 2025, EIA's forecast in real levelized 2009$ has decreased by 6% from AEO 2009 to AEO 2010

We also compared PIRA's May 2010 Power River Basin price forecast to the August 2009 forecast used in the IRP. PIRA has increased its PRB commodity forecast in real levelized 2009$ by 7% for the period 2010 through 2025.

Because PGE uses an average of PIRA and EIA coal forecasts, we believe that any change in the average is immaterial due to the offsetting updates from the two sources.

Sierra objects to the discount PGE applies to the type of coal its uses (8400 Btu/lb coal, as opposed to PRB 8800 coal). Sierra, Exhibit 1 at p. 28. In fact, PGE used a conservative discount rate in the 2009 IRP. In both PIRA's August 2009 and May 2010 short-term coal forecasts, 8400 Btu/lb coal is approximately 11.5% less than PRB 8800 coal in 2011. PGE only assumed a discount of 4.5%.

Finally, PGE did consider including a coal scenario with higher costs than those in our reference case. We did not include one because we could not imagine a plausible scenario, in light of potential future carbon legislation, state RPS's, and curtailments of less efficient and older coal plants, in which a commodity in declining demand and continued abundant supply would experience a sustained price increase.

6. Wind Integration Cost

Various parties (NWEC, RNP, and CUB) have expressed concerns regarding our wind integration costs. For example, NWEC suggests that PGE could purchase wind integration service from BPA at a lower cost. NWEC at 16.

The fundamental problem with NWEC's approach is it does not compare "apples to apples." The cost for integrating wind is highly dependent on each utility's load and generation characteristics. PGE's cost to self-integrate wind includes significant system operating requirements (related to hour-ahead and day-ahead uncertainty) that BPA's wind-integration rate does not cover.

BPA's wind balancing service reflects only the costs incurred by BPA when it reserves generating capacity on its system to meet its customers' system operating requirements for integrating wind resources. Additional charges for imbalance energy (the in-hour actual generation not matching final schedule) and persistent schedule deviations are not included. When actual wind generation is greater or less than the forecast, wind generators pay BPA a 10% penalty on the overage or shortfall, which is not included in the BPA wind balancing rate.

Wind resources also affect PGE's day-ahead resource scheduling. Day-ahead forecasts of wind availability are subject to significant forecast errors. PGE must adjust its day-ahead resource commitment schedule and purchase/sales commitments to accommodate day-ahead forecasting errors. The resulting system costs are not captured in BPA's Wind Balancing Service charges, but are costs that must be included in a comprehensive analysis of the cost impacts of wind integration.

NWEC also suggests that PGE should run a sensitivity study of integration costs to determine if any portfolios would change under a rate similar to BPA's current wind integration rate. NWEC at 16. However, aside from not being truly comparable to PGE's wind integration costs, BPA's current rate for wind balancing service will expire in September 2011, at which time a new, potentially higher rate that reflects increased wind penetration and integration demands, will take effect[11]. Therefore, running a sensitivity analysis using BPA's current rate would not provide a reliable analysis of future wind integration costs.

RNP characterizes PGE's wind integration costs used in the IRP as "inaccurate and preliminary." RNP at 2. PGE strongly disagrees. Our wind integration costs were developed using a robust study process described in our IRP. IRP at 125-129. In conducting the study we relied on assistance from a Technical Review Committee (TRC) of which RNP was a member, and which also included a representative from the Utility Wind Integration Group, the National Renewable Energy Laboratory, and two representatives from the American Wind Energy Association. We are continuing with a second phase of the study to develop a cost breakdown to compare components of PGE's Integration costs with the components of BPA's wind balancing rate. The fact that we are further refining our research does not imply that our Phase I study results were inaccurate or incomplete.

RNP states that PGE "staff were unable to answer important and basic questions about the analysis and its methodology." RNP at 2. PGE is not aware of any basic questions that it was unable to answer. PGE invited RNP staff to our offices to review

[11] See, e.g. Steve Wright, *BPA Balances Wind Services with Cost for Developers,* Oregonian, July 28, 2010, where BPA Administrator notes .that although BPA backed off a proposal to quadruple its integration rate last year, the issue of a big rate increase will come up again this year as the agency kicks off a new ratemaking process.

our modeling approach and also engaged in several question and answer sessions with our wind integration study consultant, Enernex, and the TRC, to which RNP was a party.

CUB has expressed concern regarding the use of PGE's Wind Integration study for ratemaking purposes. CUB at 1-2. This concern is misplaced here. PGE uses the Monet Power Cost model during ratemaking proceedings, which include general rate cases and annual power cost updates. The current Wind Integration costs in Monet are not taken from the values in the current IRP study or any other PGE study. Any wind integration cost estimates will be included in rates only after being added to the Monet Power Cost model in either a general rate case or an annual power cost update, which will permit all parties the opportunity to examine these costs and challenge them before the Commission if they do not believe the costs are appropriate.

7. PPA Market Reliance

A. PPAs for early Boardman Replacement and/or in lieu of Natural Gas CCCT

Sierra and NWEC assert that PGE should rely on bridging PPAs to replace the output of Boardman in the event of a pre-2020 closure. Sierra, Exhibit 1 at 13-15, NWEC at 7. NWEC and NIPPC further suggest that the region offers a surplus of available supply and that PGE should pursue mid-term PPAs in lieu of longer term supply sources such as a combined cycle natural gas plant. NWEC at 7-8, 17; NIPPC at 17-18. Sierra produces a NWPCC table showing CCCT capacity factors in the Pacific Northwest for 2007 - 2008 to substantiate the claim that plenty of available supplies will exist in the future. Sierra, Exhibit 1 at 14. The suggestion that PGE rely on mid-term PPAs suffers from several problems.

First, future availability of independent power producers and merchant resources is unknown until we issue an RFP and is likely to vary over time. The capacity factors from 2007 – 2008, which Sierra relies upon, do not ensure that these plants will be available to meet PGE's future energy needs. This is particularly true for resource requirements subject to a pre-2020 Boardman closure that would commence as early as five years from now. During a three to five year period in the last decade, three of the large, previously uncommitted independent power producer and merchant base-load power plants identified in the NWPCC table submitted by Sierra (representing over 1,000 MWs of capacity) were sold to load serving entities, thereby removing the plants from the market for power purchase agreements.[12] Potential changes in ownership or long-term commitment for just a few of the remaining large, baseload IPP / merchant plants would similarly have a dramatic impact on the future availability of mid and long-term PPAs.

Second, reliance on mid-term power purchase agreements would create undue uncertainty. Even if market supplies remain available, it is not possible to forecast

[12] Goldendale, purchased by Puget Sound Energy (PSE) February, 2007, Chehalis purchased by PacfiCorp October, 2008 and Mint Farm purchased by PSE in December, 2008.

pricing or other key structural terms (e.g. fixed price or tolling arrangement, *force majeure*, excuse of performance, availability, commitments and damages) that would be necessary to assess the cost and risk of such a strategy. In the absence of conducting a competitive bidding process, assigning a price to non-standard PPAs becomes speculative and would not be a prudent approach to assessing the cost and risk of candidate portfolios. Wholesale market liquidity and price transparency declines rapidly beyond 1-2 years from the present. As a result, forward prices for wholesale electricity would not provide a reasonable benchmark for determining the potential cost of a forward start mid-term PPA.

Third, approaches designed to remove these uncertainties have significant deficiencies. It would be unusual to enter into a forward start contract in 2010/11 for delivery starting as early as 2015, or beyond. Such non-standard contract terms are generally less attractive to potential sellers because they would preclude mid and longer term PPAs that could begin sooner. Market comparables for such transactions are also difficult if not impossible to find, which may create a "pricing premium" or further reduce product liquidity and availability.

Fourth, most of the power plants identified in the NWPCC table provided by Sierra do not have capacity available for PPAs:

- Most of the plants are utility-owned or otherwise committed under mid- or long-term sales arrangements. Of the 19 power plants listed in the Sierra "available capacity" table, 12 plants are owned by Northwest utilities. Another 3 of the remaining 7 plants listed are subscribed to Northwest utilities under purchase agreements.

- Three of the plants listed, Beaver, Coyote Springs 1, and Port Westward are PGE plants. Further, these plants are included in our load resource balance, with Port Westward and Coyote at their average output, thus they do not constitute 'unused' capacity from a planning standpoint.

The table below takes the NWPCC database of the Pacific Northwest generation and screens it to include only IPP / merchant generation (excludes IOU, PUD and government-owned plants) that is only utility-scale, baseload and dispatchable. The list has also been screened to exclude coal-fired IPP generation. Once the list is screened for the above characteristics, only the following four plants remain potential options for supplying mid-term PPAs for baseload power. [13]

[13] See NWPCC website at: http://www.nwNWPCC.org/energy/powersupply/Default.asp.

Northwest Power and Conservation Council
Uncommitted Power Plants in the Pacific Northwest
May 7, 2010

Name	Installed Capacity (MW)	Heat Rate	Site	County	State	Owner	Owner Type
Big Hanaford CC 1A-1E	322.0	7200	Big Hanaford Valley	Lewis	WA	TransAlta	Independent
Grays Harbor Energy Facility (Satsop)	650.0	7000	Satsop	Grays Harbor	WA	Invenergy (dba Grays Harbor Energy)	Independent
Hermiston Power Project	689.4	7900	Hermiston	Umatilla	OR	Calpine, dba Hermiston Power Partners	Independent
Klamath Cogeneration Project	501.5	7020	Klamath Falls	Klamath	OR	Iberdrola Renewables	Independent

Further examination of the remaining four plants reveals other potential issues. Two of the four plants (Big Hanaford and Grays Harbor) are located north of the South of Alston cut plane and are thus unlikely to be able to obtain firm transmission to PGE if they do not already have existing rights across the path[14]. The remaining two plants (Hermiston and Klamath Falls) may also be unable to deliver to PGE on a firm basis unless the owners currently hold firm rights from the plant to PGE or are able to redirect their current transmission rights (if they currently have firm transmission to another point). A firm redirect would only be allowed by BPA if doing so would not create adverse flow impacts across the most constrained paths on the BPA system (such as South of Alston). It should also be noted that Klamath Falls may not be an economically viable seller to Pacific Northwest utilities like PGE for mid or long-term sales, as the plant is particularly well situated to sell into California wholesale electricity markets at materially higher prices than those in this region.

Given this assessment, it would be imprudent to assume that PGE's future baseload energy needs can be cost-effectively supplied from market PPAs (either for a near-term Boardman replacement or in lieu of the natural gas CCCT proposed in the Action Plan).[15]

Finally, the current guidelines for IRPs and RFPs generally require procurement actions (e.g. RFPs) to follow an acknowledged IRP. Order No. 06-446 (Guidelines 1 and 7); Order No. 07-002 (Guideline 13). As a result, IRP resource evaluation should focus primarily on resource need and comparisons of cost and risk for candidate resources to meet the need –technologies, fuels and delivery methods (transportation and transmission). Questions of contract term, transaction structure risks for non-performance and capitalization method (upon whose balance sheet the resource resides)

[14] See IRP at 170 for a discussion of the transmission constraints caused by the South of Alston cutplane.
[15] A large source of merchant / IPP capacity in the Pacific Northwest is a coal plant located in Centralia, WA. The owner of the Centralia Coal plant (Trans Alta) is also currently reviewing alternatives for early closure due to pressure from environmental stakeholders and government agencies. This plant represents over 1,400 MWs of the roughly 3,000 MWs of available merchant capacity that is often referenced in Pacific Northwest regional resource adequacy assessments / forums. The potential closure of the Centralia plant could have a significant impact on the market for mid-term PPAs. See http://www.transalta.com/newsroom/news-releases/2010-04-27/transalta-and-washington-state-agree-formal-talks-transitioning-ce.

are more appropriately addressed during the subsequent procurement and competitive bidding process.

B. PPAs vs. Ownership

NIPPC criticizes the IRP for not adequately considering the potential benefits of purchasing supplies from market sources. Since the issue of "build vs. buy" is more relevant to a procurement process such as an RFP, than to an IRP, we limit our comments to matters that are relevant to the Commission in this docket.

PGE has no bias against PPAs. In our last all-source RFP (following the IRP acknowledged in Commission docket LC 33), we entered into *multiple* PPAs. These included baseload supply tied to IPP owned thermal and wind generation. We also executed market-based purchase arrangements and seasonal capacity products with merchant suppliers.

Moreover, in the 2009 IRP, we provided our analysis of the relative merits of PPAs and utility ownership as required under the Commission's IRP Guidelines. IRP Guideline 13. However, consistent with the IRP Guidelines, PGE's IRP does not focus on ownership form. Rather, it focuses on candidate technologies and fuels. As mentioned above, the proper place for evaluation of whether a PPA or ownership is more beneficial is within the RFP, based on the specific merits of the bid offerings.

NIPPC's Comments are also factually incorrect in many respects. NIPPC claims that "...S&P assigns some imputed debt while Moody's and Fitch assign no imputed debt to the same PPA portfolio." NIPPC at 9, fn. 6. As PGE is currently only rated by Moody's and S&P it would be speculative to assert that Fitch would or would not assign imputed debt to the PPAs in PGE's portfolio. We therefore address this point only as it relates to Moody's and S&P.

Moody's most recent discussion of ratings methodology concluded that "... PPAs may negatively affect the credit of utilities." *Moody's Global Infrastructure Finance, Regulated Electric and Gas Utilities, August 2009* at 31.In discussing the treatment of PPAs, Moody's states "[t]he most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station." Moody's continues, "at the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized." Based on their analysis of the PPA, Moody's treats PPAs in one of six ways, five of which result in the imputation of debt, and the sixth treating it as an operating expense.

NIPPC also states that "...S&P may assign imputed debt to PPAs as a measure of financial risk..." NIPPC at 10. This incorrectly implies that new PPAs might not result in additional debt being imputed by S&P in assigning its ratings to PGE. In general, S&P

imputes debt on all PPAs over one year in duration, and it is unlikely that any new PPA would be treated in any other manner.

NIPPC also asserts that the adjusted credit ratios resulting from imputed debt from PPAs do not adversely affect PGE's cost of capital. NIPPC at 9. In fact, those ratios are a key determinant in assigning ratings, which in turn directly affect the cost of debt. Furthermore, even if it were the case that only one rating agency imputes debt; the upward impact on the cost of debt to the Company may be the same. Our bankers have advised us, and PGE's experience has been, that in the case of multiple ratings, bonds are generally priced based on the lower rating. The differential between PGE's current A- First Mortgage bond rating and a BBB+ rating would be approximately 20 basis points. This equates to $200,000 per year for every $100 million of debt, or approximately $500,000 per year for the $250 million of debt that PGE plans to raise in 2010.

8. Renewable Portfolio Standards (RPS) Compliance

ODOE believes PGE should address renewable energy credit (REC) output available from pre-1995 biomass facilities due to passage of HB 3674, which makes such RECs available starting in 2026. ODOE at 3. In ODOE's estimation there will be "over 7 million Certificates" at such future point in time.

PGE is aware of the legislation, but did not analyze this issue in our IRP for several reasons. First, and most important, the legislation was not passed until February 2010, and signed into law on March 4, 2010, well after the initial filing of our 2009 IRP.

Second, these certificates play no role in meeting PGE's RPS requirements for the next 15 years. The substantial delay in the timing of their availability (2026) puts these RECs well outside the action plan time horizon. We do not have any of the biomass facilities that are subject to the legislation currently under contract, so their inclusion in our planning would be purely speculative.

Finally, while 7 million sounds like a large number of RECs, PGE's REC need in 2026 is forecasted at 6.75 million. If we purchased all of the forecasted biomass RECs they could only meet 20% of our load[16] for approximately 5 years (2026-2030). These RECs may indeed prove to be useful in the future. However, at this point including these RECs in our IRP planning is not appropriate due to the significant time delay in their availability for RPS use, and the uncertainty associated with acquiring the RECs.

ODOE also correctly points out that Alternative Compliance Payments could be used for future renewable project development. ODOE at 4. The crux of the argument however remains the same. PGE will be facing a large renewable need in the coming years. While use of Alternative Compliance Payments may be prudent in the case where cost-effective renewables aren't available, at the present time we believe the most

[16] We would assume the biomass RECs would be 'unbundled' RECs as defined by Oregon statute. Under Oregon RPS guidelines a utility may meet a maximum of 20% of its load with unbundled RECs.

appropriate approach is to meet the RPS obligations through the acquisition of qualified renewable resources and RECs.

9. Fuel Emissions

A. Carbon Compliance

Portland, NWEC, and Sierra focus on PGE CO_2 emissions differences between portfolios, incorrectly concluding that some PGE portfolios are not compliant with expected federal emissions standards. These criticisms focus on PGE's use of predicted allowance prices under various economy-wide or sector-wide cap-and-trade proposals being considered in the U.S. Congress as an appropriate measure of CO_2 cost. Instead, some parties urge PGE to analyze the cost of compliance under cap-and-trade programs as if a company with covered sources is required to comply with its own declining hard cap on the company's covered emissions without the availability of allowance trading or offsets investments as compliance options. According to these parties, the resulting cost of displacing carbon-emitting resources with non- or lower-emitting resources, or the cost of measures designed to reduce load through EE or DSM programs until the company-specific reduction target is reached, is the better way to assess the cost of cap-and-trade programs on the company and its customers. PGE disagrees with this characterization of how the cap-and-trade proposals would work in practice. PGE has attached a letter from the Edison Electric Institute (EEI) – the national trade association of investor-owned electric utilities with significant experience and expertise on this topic – describing the nature of the requirements that would be imposed by proposed cap-and-trade legislation. *See,* Attachment 7. EEI concludes that:

> market-based approaches such as emissions trading provide regulated companies the flexibility to achieve the emission reduction targets in the most cost-effective fashion possible, by either reducing their own emissions and selling excess allowances, or buying the additional allowances that they need from other firms (or from a government at auction). Either way, the same reductions and atmospheric benefits are achieved.

Attachment 7 at 1.

Every portfolio PGE proposes fully complies with proposed federal CO_2 standards by simulating the utilization of grants and purchases of allowances and offsets. Every portfolio includes costs based on an estimate of the future price of CO_2 carbon compliance based on a composite of third party economy-wide modeling estimates of legislative proposals. These costs are an adder within PGE's modeling to the dispatch cost of fossil-fueled resources and thus act to increasingly curtail the dispatch of coal as allowances decrease and compliance costs rise, consistent with the purpose of the legislation. Thus, each portfolio contributes its part toward achieving the carbon reductions called for in the legislation. Effective legislation would also seek to curtail the least efficient and highest cost sources of emissions first, thereby impacting smaller and older coal plants in other regions of the country prior to low-cost, more efficient plants such as Boardman.

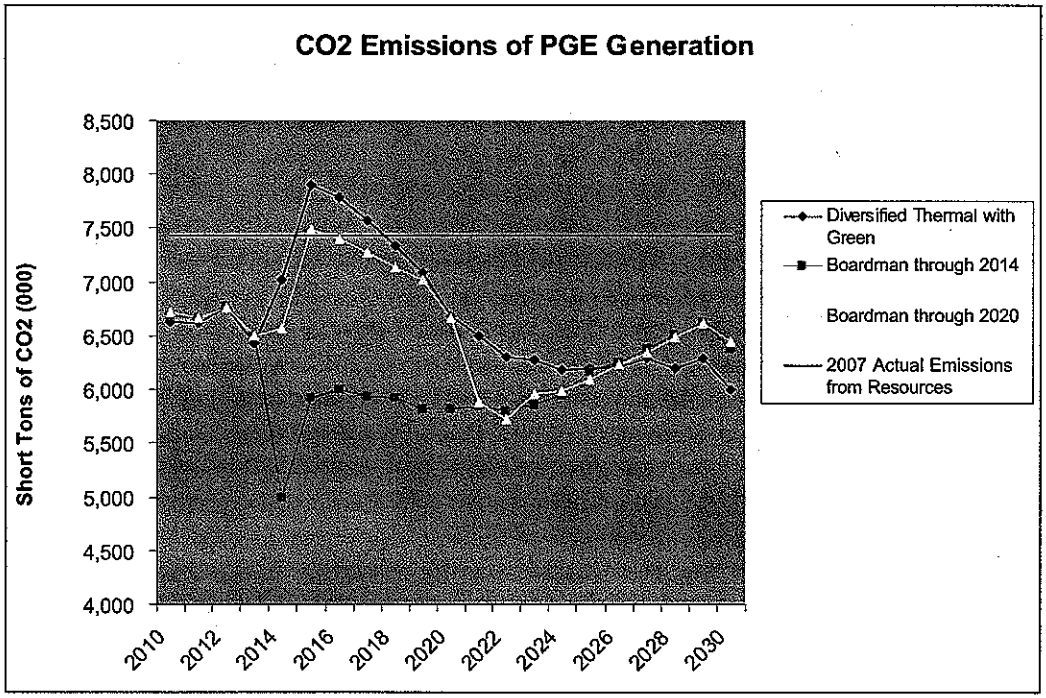
B. PGE Portfolio CO_2 Emissions

Sierra claims that PGE's CO_2 emissions increase under the Boardman through 2040 portfolios. Thus, in a presentation to the Commission on April 26, 2010, Sierra's consultant stated that:

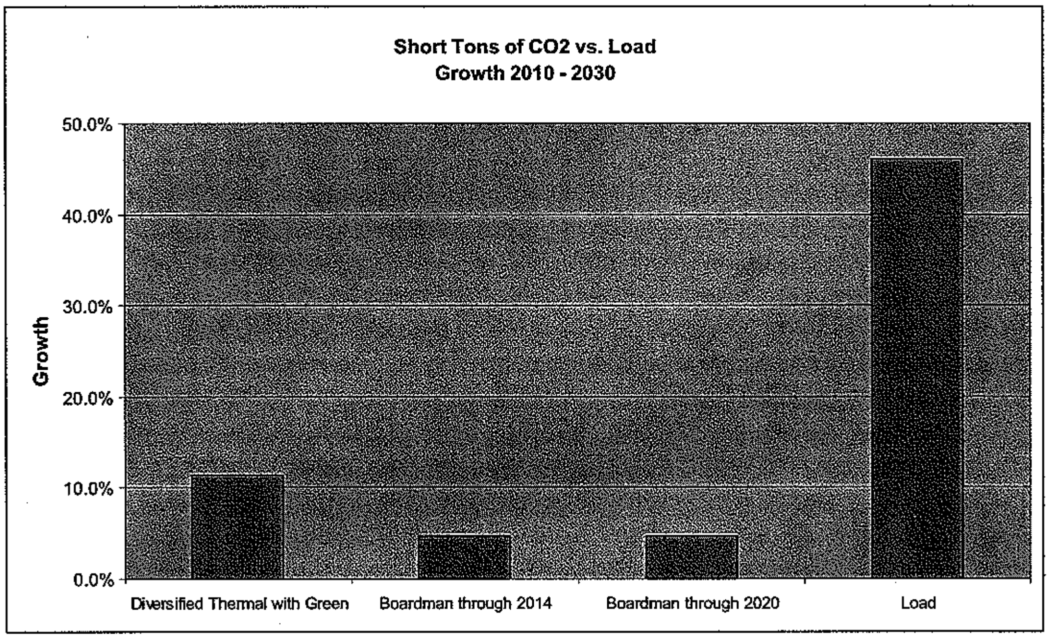
> IRP shows that if PGE continues to operate Boardman through 2040, its annual CO2 emissions would increase by approximately 30%, from 7.4 millions tons in 2007 and 7.5 millions tons in 2008 to 9.9 million tons in 2030. Annual CO2 emissions in 2030 would also be approximately 10-15% higher in 2030 in the resource plan that retires Boardman in 2020.

Schlissel Technical Consulting, *PGE 2009 Integrated Resource Plan Preliminary Findings,* p. 5 (August 26, 2010).

Sierra's statement is misleading. The 2007 and 2008 actual emissions stated above represent emissions from that portion of PGE's load which is only served PGE-owned generation, whereas the 9.9 million tons in 2030 is for PGE's entire load. In order to compare on a retail load basis, see the following graph which shows annual emissions from PGE-owned generation only for the Diversified Thermal with Green, Boardman through 2020 and Boardman through 2014 portfolios. As is shown, the 2030 CO_2 emissions from PGE-owned generation are lower than 2007 emissions in all cases, indicating the impact of carbon legislation.



When increases in load are factored into the analysis, emissions intensity sharply declines. As is shown in the figure below, our load is forecast to grow by 46% over the period 2010 - 2030, while our total emissions to meet all retail load (including generation, market and contracts) increases by around 5-11%, depending on the portfolio. Emissions are decreasing when measured on the basis of emissions per MWh of load in all three portfolios. This underscores the difficulty of absolute CO_2 reductions in the face of ongoing load growth and the loss of zero-emitting hydro resources for a utility that is already a low emitter compared to most U.S. utilities.



C. Carbon Cost

NWEC compliments us for using a reasonable reference case carbon compliance cost but criticizes PGE's use of multiple CO_2 cost scenarios in our risk analysis. NWEC asserts that we assign no weighting scheme to the use of high and low CO_2 cost forecasts to reflect their respective likelihood of occurrence. NWEC at 15. NWEC's criticism ignores the Commission's IRP Guidelines that require the use of different CO_2 cost forecasts:

> The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities.

IRP Guideline 8a.

Consistent with Guideline 8, PGE developed several scenarios using a variety of CO_2 cost forecasts. IRP at Chapter 6.4. PGE also developed a specific trigger point analysis of CO_2 costs in accordance with IRP Guideline 8c. IRP at 278. Finally, as required by IRP Guideline 8d, PGE developed the *Oregon CO_2 Compliance* portfolio which is consistent with Oregon energy policies. In short, PGE has complied with all of the Commission's CO_2 IRP Guidelines respecting CO_2.

NWEC does not suggest a weighting scheme, nor do we believe at this early stage that it would be informative to speculate on the likelihood of any given set of CO_2 compliance costs over time.

ODOE notes that the carbon price used in our reference case is "[l]ower in comparison to other cost estimates from the region and baseload generation providing utilities." ODOE at 1. At the time of our analysis, PGE constructed the reference case scenario to reflect the most likely regulatory compliance future as required by IRP Guideline 8a. PGE reviewed studies commissioned by Congress under the Bingaman-Specter Lieberman-Warner, McCain-Lieberman and Waxman-Markey congressional legislative proposals and an EPA legislative study of the Waxman-Markey bill. The 2009 IRP discusses how the reference case cost is derived, as well as the other cases used in the IRP. 2009 IRP at 103.

PGE's CO_2 cost estimates align closely with other utilities' estimates. For example, Avista's 2009 Electric IRP assumes a price of $33.37 per short ton (2009$), which is only a little over $3 per ton more than PGE's 2009 IRP reference case.[17] Moreover, in a technical support document prepared for the U.S. Department of Energy, the interagency group on social cost of carbon proposed a central estimate of approximately $21 per ton of CO_2 starting in 2010 which grows over time to about $45 per ton by 2050 (2007$).[18] This analysis yields a price of about $30 in 2009 dollars.

Most reliable sources acknowledge that there is a wide range of reasonable CO_2 price forecasts. In their 6th Power Plan, the NWPCC states that the "range of estimates is very wide".[19] The NWPCC is not taking a position on carbon policy for the region and simply explored a wide range of possible carbon prices. Taking into account the broad price range of potential CO_2 costs, PGE constructed a reasonable estimate based on the most recent information available at the time.

The following figure shows the 2009 IRP CO_2 forecast in comparison to the more recent Kerry-Lieberman proposal. As is shown, PGE's low case of $12 case is consistent with the Kerry-Lieberman floor price, PGE's $65 high case is much higher than the Kerry-Lieberman ceiling, and PGE's reference case ($30) is only slightly higher than the Kerry-Lieberman average.

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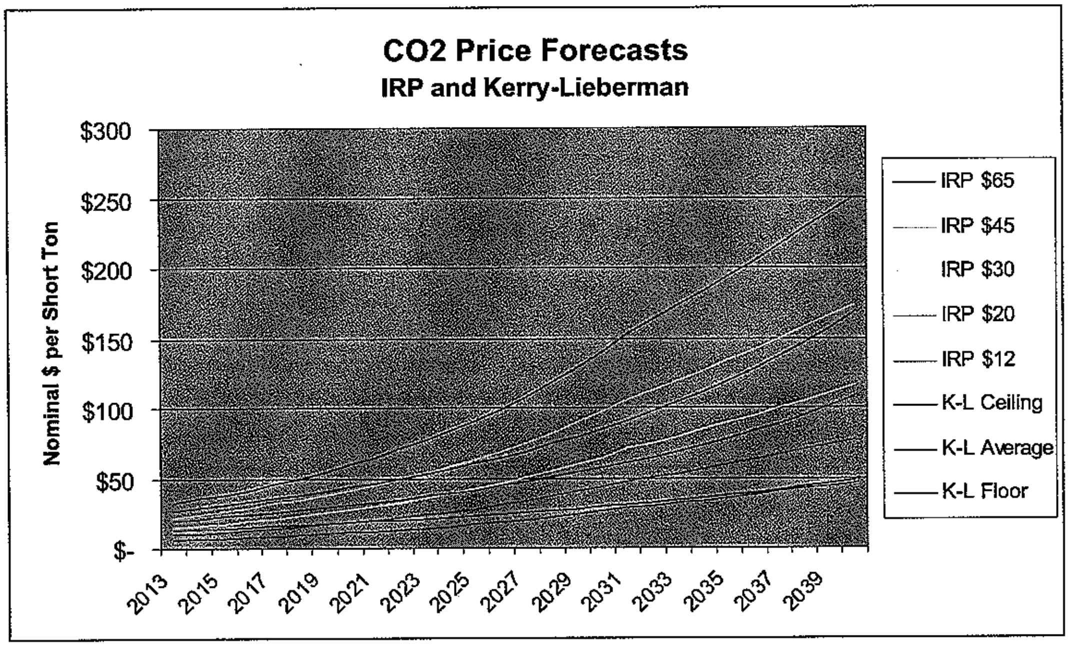
[17] Avista 2009 IRP (pg 4-11)

[18] U.S. Department of Energy (2010), "Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors," Appendix 15A (by the Interagency Working Group on Social Cost of Carbon): "Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866," available online at http://www1.eere.energy.gov/buildings/appliance_standards/commercial/sem_finalrule_tsd.html.

[19] Northwest Power and Conservation NWPCC 6th Power Plan, 2010 Ch. 2 (pg 10).



Finally, CUB focuses on the uncertainty around CO_2 costs, concluding that "PGE's approach probably overstates carbon compliance in the short run and understates those costs in the long run." CUB at 9. While we do not agree with their conclusion, CUB's statement highlights the uncertainty around any potential carbon regime going forward. However, if CUB is correct and PGE's early CO_2 costs are too high, our preferred portfolio, which proposes to close Boardman in 2020, is actually disadvantaged under our current assumptions.

D. Other Emissions

PSR comments on health impacts due both to climate change and to criteria emissions from Boardman. PSR at 1-2. Elsewhere in this document, we demonstrate that PGE will be in compliance with projected federal legislation for CO_2, and all existing rules and legislation for other regulated emissions for all IRP candidate portfolios. PGE believes that it is important to operate our business in a manner that is socially and environmentally responsible. We further recognize that it is important to consider human health impacts associated with our business decisions and operations. However, potential health impacts related to carbon emissions are not within the scope of the Commission's IRP Guidelines.

10. Risk Metrics

A. HHI

Many parties were confused by PGE's use of HHI as a measure to capture portfolio diversity. For example, Sierra's consultant appears to confuse HHI with other risk measures such as high construction cost and technology uncertainty. Sierra, Exhibit 1 at 36.

As discussed in our 2009 IRP filing, HHI is used routinely to measure market concentration (i.e., the number and market share of competing companies). Theoretically this metric can range from 0 (a market with an infinite number of competitors all with equal market share) to 10,000 (a market with a single supplier). If a market had one hundred suppliers, each with one-percent of the market the HHI would equal 100 (100*[1%^2]). The more diverse the market, the lower the HHI value; the more concentrated the market, the higher the HHI. PGE adopted this framework as a way to evaluate differences in generation technology and fuel concentration (exposure) in our candidate action plans.

For the Fuel HHI measure we examined the fuel source of the energy used to meet PGE load for the period 2010-2021 (the last year for major resource acquisition). Portfolios that include wind, other renewables types, and/or nuclear tend to show better fuel HHI values because these portfolios have a more diverse fuel supply, which would tend to help minimize risks associated with fuel supply.

For the Technological HHI we examined the nameplate capacity of the resources for each portfolio in the year 2021. The idea here is akin to the adage of avoiding all eggs in one basket – or in this case, one or few generation technologies. Here portfolios with a more diverse set supply and demand-side technologies (as measured by nameplate) will do better. Thus the nuclear and market portfolios performed well. These portfolios have more diverse sources of supply than, for example, the early Boardman closure portfolios with their heavy CCCT concentrations. As with the Fuel HHI, the Technological HHI does not look at construction or capital cost. These risks are modeled more directly, in our futures analysis where we look at high capital costs.

B. TailVar less Mean Metrics

NWEC expresses concern over the use of a metric that looks at the difference between right-tail (i.e., "bad") outcomes and mean or reference case outcomes. These are the "Deterministic Portfolio Risk Variability vs. Reference Case" and "Stochastic Portfolio TailVar90 less Mean" metrics described in the IRP at 249. The purpose of these metrics is to assess the relative exposure of a portfolio to cost variability. Specifically, NWEC states "Any metric such as these that subtracts out the mean, in cases where the mean can be very different across tested portfolios, is faulty, since high variability in itself is not a bad outcome. Only high absolute costs are bad." NWEC at 13. We believe that avoiding bad outcomes and avoiding large cost variations both matter, although they largely capture different aspects of the same kind of risk. In any event, this type of measurement is required by IRP Guideline 1c: *"[t]o address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes."* The Order adopting the IRP Guidelines does not indicate that any party objected to the Commission's adoption of either metric. *See,* OPUC Order 07-002.

C. Year-to-Year Variance Metric

NWEC also does not like the use of the year-to-year variance described on page 250 of the IRP, NWEC at 14. This is the only PGE metric that looks at year-to-year potential rate variation due to variability of our five stochastic variables (natural gas prices, weather-induced load variations, hydro years, plant forced outage power cost impacts, and wholesale electric prices) and comprises 3.3% of our total score. In previous IRPs, a precursor metric, RVI, or Rate Volatility Index, was a prominent risk metric. Relative rate stability is important to our customers, particularly to business customers that tend to budget and forecast expenses for electricity three to five years out. Without the use of a cost variability measure such as Year-to-Year Variance we would not be able to determine which portfolios exhibit high or low cost variability and are thus more or less likely to provide the rate stability that our customers prefer. It is worth noting that no serious concerns with the use of the RVI metric were cited in prior IRPs where the measure was used more prominently to consider rate variability. We believe this metric continues to provide useful information about the "bumpiness in the road" with regard to electric costs for PGE customers. Moreover, as this is a measure of variability of costs, we believe this metric contributes to compliance with the Commission's IRP Guidelines.

D. Reliability Metric

NWEC expressed concern with PGE's use of a reliability metric. Their rationale appears to be that all portfolios should be built to the same reliability level. NWEC at 14. PGE believes this suggestion is impractical and would make reliability performance harder to evaluate.

Currently, calculating reliability performance is the most time- and data-intensive portion of portfolio modeling, as we model random forced outage rates and mean times to repair for all of our generating plants for all hours for all portfolios for 100 iterations for 10 years and then gather up the performance statistics. (If time permitted, we would increase the number of iterations.) It is impractical to back in to a given result by repeating this process several times while varying plant nameplate amounts until all portfolios have achieved the same reliability. It also would require picking the desired level of reliability and the desired reliability metric (LOLP, EUE, TailVar EUE). Further, it ignores that plants come in certain sizes that don't allow for scaling up or down to meet a reliability target.

In addition, building all portfolios to the same overall reliability level would mask the causation for differences between costs driven by plant ownership and operations versus costs for acquiring additional generation for reliability The suggested approach would obscure the varying degree of reliability performance inherent in each resource type and portfolio. For example, under our current approach, one portfolio might provide only slightly higher reliability for much higher cost. Such a trade-off would be masked if all candidate portfolios were constructed to achieve the same level of reliability. PGE's

IRP approach of constructing portfolios that achieve the same overall capacity and energy levels allows for a fair comparison of all performance metrics, where reliability performance is a stand-alone metric which can be seen and measured separately. Our approach thus provides visibility about the trade-offs between cost and various types of risk including cost versus reliability risk.

Moreover, OPUC IRP Guideline 11 provides guidance on the purpose of reliability analysis, "Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered." OPUC Order No. 07-002 Appendix A, at 7. Under NWEC's proposal, as each portfolio would be pre-set to have the same level of reliability, reliability would not be analyzed in the manner required by the Guideline, Doing so makes reliability a modeling input rather than a result or output that can be assessed and compared across portfolios.

11. Portfolio Considerations

A. Optimization

NWEC and Sierra's consultant call for PGE to employ optimization modeling to help derive and identify preferred portfolios. NWEC at 4; Sierra, Exhibit 1 at 13. Neither party attempts to link this perceived shortcoming to their opposition to Boardman operations or to PGE's proposed Action Plan. As a result, we question the relevance of the concern to this IRP.

We can concede that, if there were no constraints on time and resources for IRP, optimization modeling could potentially provide some insights. However, we question whether the increased time, cost and complexity would actually help us reach better decisions. More complexity does not always provide better answers; sometimes it just provides more complexity.

The portfolio optimization approach may also have limited utility due to the natural constraints in our resource choices. There is simply a limited number of legitimate resource types (generation technologies and fuel types), and each resource type has an inherent size that is driven by technology. For example, today's high efficiency natural gas combine cycle plants are roughly 400 MW in size. Constructing a portfolio through an optimization tool with a CCCT sized at 150 or 550 MWs would not be valid as it would require speculation about commercial arrangements for sharing the plant. Co-ownership and joint dispatch of a single shaft gas plant poses many problems and is therefore rarely implemented in practice. In fact, the vast majority of all recent vintage high efficiency gas plants in the west are owned and dispatched by a single entity. In a world where we have both a constraint on the number of resource types (generally less than 10), and those resource types are constrained in the size that they can be deployed, use of an optimization tool to derive portfolios may have limited value.

In addition, optimization typically employs one objective function (e.g., cost minimization) and various known constraints. For instance, we have employed linear optimization in building a PGE system-specific model to determine costs associated with wind integration and ways to mitigate those costs. However, in IRP portfolio modeling, we have multiple objective functions (e.g. cost, cost-risk and reliability), as well as constraints that are subject to great uncertainty. Simply put, optimization faces challenges in the context of an IRP where there is not a single objective function, but rather multiple functions. The method and weightings used to "optimize" could overwhelm an already complex process.

As NWEC indicates, optimization will result in "tweaks" to the portfolios (NWEC at 11), in which ever smaller adjustments are made to the timing and the relative mix between wind and gas resources. Nevertheless, certain "tweaks" may call for speculation and render a plan un-executable. As stated above, generating resources come in certain unit sizes which are not amendable to small changes to accommodate optimization. Moreover, neither NWEC nor any other parties suggests that "tweaks" to the portfolios will have a material impact. In fact, as suggested above, minor tweaks will likely increase the clustering of results which NWEC also criticizes. NWEC at 14.

B. Expected Value

NWEC points out that our use of the term "expected value" when describing the NPVRR cost outcome for a given portfolio under deterministic reference case assumptions is misleading. NWEC at 8. To clarify, we did not mean "expected value" in the narrow statistical sense of describing the mean of a stochastic distribution. Rather, we meant "expected value" in the broader sense of costs that would be expected using reference case assumptions – that is, assumptions that are generally thought of as being most likely to occur. Oftentimes, our reference case assumptions also fall roughly in the middle of a reasonable range of sensitivities. Hence, for example, we used reference case assumptions that are approximately in the middle of the range of values evaluated for gas prices, loads, and CO_2 compliance. While weights or probabilities are not assigned to them, they can be thought of as the "most likely" or "expected" values. They can be thought of as being in the approximate middle section of a range and so are analogous to expected values, while clearly not being as stringent.

C. Statistically Significant Results

NWEC observes the clustering of results and questions whether the difference between the portfolios is statistically significant enough to provide a reasonable basis for selecting the best preferred portfolio. NWEC at 4, 8, 10. We answer this with three clarifications:

First, 75% of our score is based on deterministic scenario analysis and another 15% is a reliability metric. The remaining 10% of our score employs stochastic analysis where draws for a limited set of stochastic variables is employed. Hence, applying statistical tests for significance is not applicable for most of our scoring because most of the analysis is deterministic in its nature.

Second, the clustering is not nearly as tight as it appears to be. For each portfolio, the majority of portfolio costs are from embedded assets, not incremental resource actions. For instance, in the Market Portfolio, which employs no major new resource actions other than maintaining RPS compliance and ongoing EE, incremental costs make up about one-third of the total portfolio cost. Additionally, a significant portion of the incremental costs are due to actions that fall outside our Action Plan window and are common to most portfolios. Assuming that a third of these incremental actions occur outside the Action Plan window, then the true incremental cost of each portfolio is closer to 22% of the total portfolio cost (33% * 67%). To illustrate the impact, assume two portfolios, one that has a NPVRR of $100, the other of $97. While this 3% difference doesn't seem particularly significant, on the incremental portion of the portfolio, it is the difference between $22 and $22 minus $3, or $19. Now the perceived 3% difference is actually an incremental difference of 13.6% – four and a half times higher than when embedded costs common to all portfolios are included. Using incremental differences would also be the appropriate basis for a test of statistical significance (if applied to a stochastic analysis rather than a deterministic scenario analysis).

Third, a certain degree of clustering is expected. Since we are building new resources to meet the same load in all portfolios and there is a very limited choice of new generation resource options available, it is not surprising that top-performing portfolios tend to have relatively small differences in total amount of new resource additions and the cost of those additions. These differences in portfolio performance would only become closer with a portfolio optimization technique. Nonetheless, even with the performance across portfolios, the NPVRR differences between portfolios are still in the tens and hundreds of millions of dollars, which is significant to our customers.

D. Scenario versus Stochastic Analysis

NWEC also appears to suggest that stochastic analysis should form the primary basis for risk analysis, apparently at the expense of scenario analysis. NWEC at 4, 8. More specifically,, NWEC suggests that stochastic analysis should be used to derive the reference case NPVRR. NWEC at 8. However, PGE believes the value that stochastic analysis adds is in understanding the potential volatility of the NPVRR results. Use of stochastic modeling should not change any of the expected costs of the modeled portfolios.

As pointed out in Section C above, stochastic analysis can only be applied to inputs that are stochastic in nature. For the 2009 IRP, this means stochastic analysis can be applied only to five variables (one of which is a function of the others). The bulk of other inputs are subject to deterministic scenario analysis.

Sierra's technical consultant explains why, in their view, scenario analysis is of greater importance: "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." Sierra, Exhibit A at 25. In short, PGE believes the role of stochastic analysis is to supplement, not supplant, scenario analysis.

E. CO_2 Compliance Cost as a Stochastic Variable

Sierra suggests that PGE's IRP is incomplete as we do not treat CO_2 compliance costs as a stochastic variable. Sierra at 25. Typically, stochastic variables exhibit short-term volatility that is not particularly related to longer-term fundamentals. Stochastic distributions are traditionally drawn from historical data. There is no historical basis for developing a probability distribution governing the likelihood of certain CO_2 compliance cost or their volatility. Therefore, in order to develop such a distribution for CO_2 costs, we would need to speculate about the distribution shape and dispersion. Such an analysis would be based on unsupported assumptions and therefore would not provide any reliable information. This issue was recognized by Lawrence Berkeley Labs in a March 2009 report entitled "Managing Carbon Regulatory Risk in Utility Resource Planning" at page 11:

> ***Uncertainty in input variables for which historical data do not exist – such as carbon emission prices – is less amenable to probabilistic definition and stochastic modeling.*** Cost uncertainty associated with these types of variables is therefore often assessed by calculating candidate portfolio costs across a discrete number of alternate scenarios (i.e., scenario analysis rather than stochastic Monte Carlo analysis). (*emphasis added*)

Sierra's consultant also recognized the uncertainty inherent in predicting future CO_2 regulation and put forward scenario analysis as the "appropriate" way to consider CO_2 pricing:

> Given the significant uncertainty in the timing and design of CO_2 regulatory programs, we believe that the use of a range of CO_2 prices, such as that represented by the Synapse Low and High CO_2 Price Forecasts ($15/ton to $45/ton on a levelized basis between 2013 and 2030) is appropriate in utility resource planning.

David Schlissel, *et. al.,* Synapse 2008 CO_2 Price Forecast, July 2008, at 16. This type of scenario analysis is just what PGE performed in our 2009 IRP modeling.

F. Scoring Grid

NWEC objects to PGE's IRP scoring grid. While its discussion on this was extended, we make a few simple points.

First, Order 08-2146 at 7 requires a tabular format; this is expanded on at 15 and then repeated at 17. The order specifically called for "a rank ordering of all the portfolios based upon all of the considerations."

Second, because the Commission was not prescriptive in exactly how this was to be accomplished, PGE developed a grid that we believe provides reasonable category weightings and provides visibility into our approach for identifying top performing portfolios that are candidates for a preferred portfolio. We introduced the scoring grid in its draft form and then in its current form in two IRP public meetings as a way to meet the Commission requirement and to provide insights into PGE's rationale for integrating the various IRP performance metrics for candidate portfolios. While some parties provided feedback concerning the proposed performance metrics, we did not note any serious stakeholder concerns with the overall scoring grid approach.

Third, the scoring grid approach is merely a screening mechanism to identify better performing portfolios that are potential candidates for a preferred portfolio and ultimately an IRP Action Plan. The purpose and intended use of the scoring grid is explained in more detail in the IRP at 250-251. The scoring grid does not supersede sound judgment in making a final selection. The real value in a scoring grid or similar approach is that it provides insights and transparency for stakeholders into the use of our various performance metrics in screening and rank ordering candidate portfolios.

Fourth, the IRP scoring grid methodology is quite similar to the scoring approach that PGE has used in our RFPs, where we employ a point system with 60% being based on cost and 40% on qualitative considerations. This RFP approach has been vetted with two separate independent evaluators and OPUC staff.

Finally, we note that while critical of the scoring grid, neither NWEC nor any other party suggests a constructive alternative.

CONCLUSION

We appreciate the interest parties have shown in our IRP and the substantial resources they have committed to this process. We have conducted numerous public stakeholder meetings, presented our assumptions, modeling methodologies and results, while also seeking – and greatly benefiting from – stakeholder feedback. Throughout the process, we have complied with the spirit and letter of the Commission IRP Guidelines.

Our Action Plan calls for a mix of new energy efficiency, renewable resources and efficient natural gas generation for both energy and capacity needs. Our preferred Boardman actions would set a national precedent by defining a reasonable path for utilities to transition to non-coal fuel resources where appropriate. If BART III is not approved by the EQC, our best and most responsible action remains full implementation of controls and continued operation of the Boardman plant through at least 2040. Our proposed Cascade Crossing transmission project will bring much needed transmission capacity to the Pacific Northwest thereby enhancing reliability and providing greater access to renewable generation.

Given the lead times for construction of new generation and transmission, as well as the timelines to meet the requirements of DEQ rules, PGE seeks acknowledgement of the Action Plan so that we may move forward in a timely manner to implement the resource decisions.

DATED this 10th day of August, 2010.

Respectfully submitted,

/S/ V. Denise Saunders

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APPENDIX A

These Reply Comments use the following abbreviations to identify Parties submitting comments:

PARTIES	ABBREVIATION
Citizens' Utility Board	**CUB**
City of Portland	**Portland**
Ecumenical Ministries of Oregon	**Ecumenical Ministries**
Northwest Energy Coalition	**NWEC**
Northwest Intermountain Power Producers Coalition	**NIPPC**
Oregon Department of Energy	**ODOE**
Oregon Public Utility Commission Staff	**Staff**
Physicians for Social Responsibility	**PSR**
Renewable Northwest Project	**RNP**
Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge & Northwest Environmental Defense Center	**Sierra**
Willard Rural Association	**Willard**

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PGE's 2009 Integrated Resource Plan

Attachment 1

PGE's DEQ Comments

PGE
Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8928 • Facsimile (503) 464-2222

Stephen M. Quennoz
Vice President
Power Supply/Generation

July 30, 2010

Mr. Brian Finneran
Oregon Department of Environmental Quality
811 SW Sixth Avenue
Portland, OR 97204

Re: Comments on draft Regional Haze rule revisions

Dear Brian:

Thank you for the opportunity to comment on the Department of Environmental Quality's draft control options for the Boardman Power Plant, as described in the department's June 28 announcement of potential Regional Haze rule revisions. The attached document provides Portland General Electric's detailed assessment of the draft options, along with proposed resolutions to issues associated with those options.

We believe a 2020 timeframe remains the best path to achieve applicable environmental standards for the Boardman Plant at a reasonable cost to our customers while maintaining reliable electric service. While DEQ does not have the authority to impose a closure date on the Boardman Plant or a closure decision on PGE, the agency has the authority and latitude to make policy decisions that would allow development and implementation of a reasonable 2020 plan. We urge the department to work with us within that framework to determine an appropriate control strategy.

We should not lose sight of the fact that agreement on a responsible 2020 closure plan would represent a significant national precedent, defining a reasonable path for utilities to transition to non-coal fuel sources where appropriate rather than invest in expensive control solutions. We have a chance to create a powerful model of collaboration that could have a highly beneficial impact on air pollution in the United States, shaping national strategies for power plant emission reductions.

Our attached comments offer corrections to technical and methodological flaws in DEQ's analysis. Unfortunately, while we know that DEQ shares our intention of seeking an appropriate alternative to implementation of full controls and continued operation of the Boardman Plant through 2040, we believe the agency has reached a number of invalid conclusions that render unworkable all three of the draft options outlined on June 28.

PGE already has a clear path to resolve all current emissions requirements for the plant (defined in DEQ's 2009 Regional Haze rule) and continue operation for at least the next 30 years. We chose not to leave it at that, however, because PGE and numerous customer and stakeholder groups agree that an even better solution for our customers and the environment would be possible if the DEQ rules allowed us to meet Regional Haze objectives through a combination of interim controls and early plant closure.

If an acceptable amendment to the 2009 rules can't be achieved and the options described by DEQ are carried through as drafted in your final rule amendments, our best and most responsible course of action remains full implementation of controls and continued operation of the plant through at least 2040. While extensive modeling confirms that the 2040 path would be a responsible, cost effective course of action to serve our customers, it would be unfortunate to lose this opportunity to achieve an even better outcome.

This makes it imperative that DEQ's formal proposed rule include a workable 2020 option. We strongly disagree with DEQ's conclusion that the 2020 plan we proposed in April could not be approved under EPA Regional Haze standards for Best Available Retrofit Technology. Nevertheless, we have taken the opportunity afforded by this informal comment period to conduct additional analysis to respond to DEQ's concerns. As a result, we have modified our proposal to capture additional interim control benefits, substantially reflecting DEQ's suggested control options.

Specifically, our attached comments propose operation on reduced sulfur coal, low-NOx burners, modified overfire air and selective non-catalytic reduction (SNCR) through 2020 with a pilot study of Dry Sorbent Injection (DSI) technology. Contingent on the results of pilot testing, PGE would commit to meeting a 0.4 lb SO_2/MMBtu limit through 2020 using DSI. If this option is considered BART, DEQ would need to provide a procedure for establishing an alternative SO_2 limit based on the testing. The limit would be adjusted if PGE's pilot testing demonstrated that operation of DSI could not reach 0.4 lb SO_2/MMBtu, when operating in conjunction with SNCR and the mercury controls, without resulting in an increase in the hourly capacity to emit particulate matter or triggering PSD for $PM_{2.5}$ (assuming the same level of operation currently reflected in the Boardman Plant's plant site emission limits).

While this proposal includes a closure requirement in 2020 that is clearly enforceable, one of the corollary advantages of the 2020 option is that it also allows sufficient time for an evaluation of whether the plant could be efficiently operated using a different, non-fossil fuel source. Of course, this would require a new permit, following a separate DEQ review.

The reason for going through this lengthy process is to achieve the best solution we can for our customers, one that balances environmental impacts with customer cost impacts. If we succeed, PGE will be well positioned to meet our customers' needs today, while at the same time laying the groundwork for better supply options for Oregon's and the nation's energy future.

We believe DEQ should consider this combination of pragmatism and precedent as it seeks an appropriate solution in this matter, and we stand ready to work with the agency to that end. Please do not hesitate to contact us if you have questions or would like more information regarding the attached comments.

Sincerely,

Stephen M Quennoz

cc: Dave Robertson
Jim Lobdell

PGE COMMENTS ON DEQ'S PROPOSED REVISIONS TO ITS REGIONAL HAZE RULES

7/30/2010

Portland General Electric Company ("PGE" or "Company") appreciates this opportunity to comment on the Oregon Department of Environmental Quality's ("DEQ" or "Department") preliminary revisions to its Regional Haze rules. As you know, the rules are the result of the federal requirement that Oregon develop an implementation plan for regional haze (the "Regional Haze Plan") for submittal to EPA and approval into the State Implementation Plan ("SIP"). The Regional Haze Plan must include a determination of Best Available Retrofit Technology ("BART") for each BART-eligible source in the state that emits any air pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I area. 40 CFR § 51.308(e)(1)(ii). The federal Clean Air Act contains specific criteria for establishing BART and these criteria are carried over into the regulations. In developing these regulations, EPA also promulgated guidelines to be used by the states in developing BART determinations. These guidelines, found in 40 CFR § 51 Appendix Y, contain the majority of the detail regarding how BART determinations are to be conducted.

What follows is a summary of developments thus far in the BART determination rulemaking process for PGE's Boardman Power Plant, PGE's assessment of the draft control options described in DEQ's June 28 announcement and invitation for public comment, and our proposed resolution to problems associated with those options. We will also address concerns DEQ raised with respect to the alternative 2020 plan PGE proposed in the petition submitted to DEQ on April 2, 2010.

As we review the technical details of potential control solutions, however, it's important that we not lose sight of why we are revisiting this issue. After all, the EQC has already adopted rules that would allow PGE to resolve all current emissions requirements for the plant and continue operation for at least the next 30 years, an outcome that extensive modeling confirms would be a responsible, cost effective course of action to serve our customers. We have chosen not to leave it at that, however, because PGE and numerous customer and key stakeholder groups have agreed that it would be possible to achieve an even better outcome for both our customers and the environment if the DEQ rules are revised to allow us to instead meet Regional Haze objectives through a combination of interim controls and early plant closure.[1]

[1] Early closure, as referenced herein, is the cessation of coal as a fuel source for the Boardman plant. PGE is evaluating other technologies for use at the Boardman site, including biomass.

The reason for doing this, if we're able to finalize an acceptable amendment to the rules, is to achieve the best solution we can for our customers. This also gives us an opportunity, however, to set a remarkable national precedent for Regional Haze regulation and, for that matter, for general air quality regulation of coal-fired generating plants nationwide.

Although a few coal-fired plants in the United States have recently been slated for closure and replacement, none of the plants involved to date match Boardman's age, size, level of efficiency or role in a utility generating fleet (i.e. a baseload resource). In short, PGE and its stakeholders have stepped forward to match a pragmatic resource decision on behalf of customers with a forward-looking policy precedent that could have a significant impact on the nation's efforts to reduce air pollution in general and carbon emissions in particular.

We believe DEQ should consider this combination of pragmatism and precedent as it seeks an appropriate solution in this matter. Specifically:

- Given the substantial discretion and flexibility the states have under the BART requirements of CAA § 169A,[2] Oregon clearly has the authority to develop a reasonable path to plant closure. An innovative approach along the lines of what PGE has proposed would be consistent with Regional Haze regulations while also offering a valuable example for other utilities and states to follow. This could result in tremendous cumulative national air quality benefits that potentially dwarf the results of any action Oregon could take by itself.
- In order to achieve an attractive national precedent, however, DEQ must balance the considerable long term benefits of closing a coal-fired power plant of this size with the near-term need to mitigate costs to customers, maintain the reliability of the electric power grid, and reduce the economic impact of closure on communities surrounding the

[2] "H.R. Conf. Rep. No. 95-564 (1977), reprinted in 3 Senate Comm. on Env't and Pub. Works, A legislative History of the Clean Air Act Amendments of 1977, at 535 (1978) [hereinafter "1977 Legislative History"]. The "agreement" to which the Conference Report refers was an agreement to reject the House bill's provisions giving EPA the power to determine whether a source contributes to visibility impairment and, if so, what BART controls should be applied to that source. See id. At 533-35. Pursuant to the agreement, language was inserted to make it clear that the states - not EPA - would make these BART determinations. See id. at 533-35; see also H.R. Res. 4151, 95th Cong. (1977), reprinted in 1977 Legislative History at 1985, 2325-30. The Conference Report thus confirms that Congress intended the states to decide which sources impair visibility and what BART controls should apply to those sources. *American Corn Growers et al. v. EPA, 291 F. 3d 1 (D.C. cir. 2002)*

plant. Failure to do this would instead establish a precedent that greatly reduces the incentive for utilities, state regulators, and stakeholder groups to seek collaborative emissions control solutions based on early plant closure.

In our comments below, PGE offers suggestions on how to address key provisions of the Regional Haze rules and the BART guidelines to accomplish a reasonable 2020 closure of the Boardman Power Plant. Specifically, we propose operation on reduced sulfur coal, low-NOx burners, modified overfire air and selective non-catalytic reduction ("SNCR") through 2020 with a pilot study of Dry Sorbent Injection ("DSI") technology. Contingent on the results of pilot testing, PGE would commit to meeting a 0.4 lb SO_2/MMBtu limit through 2020 using DSI. If this option is considered BART, DEQ would need to provide a procedure for establishing an alternative SO_2 limit if PGE's pilot testing demonstrated that operation of DSI could not reach 0.4 lb SO_2/MMBtu, when operating in conjunction with SNCR and the mercury controls, without resulting in an increase in the hourly capacity to emit particulate matter or triggering PSD for $PM_{2.5}$ (assuming the same level of operation currently reflected in the Boardman Plant's plant site emission limits).

We remain mindful that if an acceptable amendment to the 2009 Regional Haze rules cannot be achieved, our most responsible course of action remains full implementation of controls and continued operation of the plant to serve our customers through at least 2040. While this would be an unfortunate and unnecessary outcome, we believe that it will still be the best plan available to us if the other options described by DEQ are carried through as drafted to the final rule amendments.

DEQ and the EQC have discretion under § 169A to achieve a balanced and reasonable outcome that will benefit both the environment and utility customers. We urge the agency to approach this issue with that flexibility in mind, remembering that ultimately the rules are intended to achieve results that will make both environmental and economic sense to the people we serve. We look forward to working with you to take advantage of this opportunity to set an important national precedent.

1. Background

On November 2, 2007, PGE submitted a BART analysis for its coal-fired power plant located in Boardman, Oregon (the "Boardman Plant").[3] Sources in existence on August 7, 1977 and that both fall into one of the designated source categories and have the potential to emit more than 250 tons per year of a haze-causing pollutant are required to determine BART if they cause or contribute to visibility impairment in a mandatory Class I area. 40 CFR § 51.308(e). DEQ previously determined that the Boardman power plant was in existence, as that term is defined in the federal Regional Haze program, on August 7, 1977.[4] The Boardman Plant emits more than 250 tons per year of NOx, SO_2 and PM, is in one of the designated source categories and was determined by the Department to cause visibility impairment in at least one mandatory Class I area. Therefore, PGE engaged an extensive group of experts that assisted the Company in preparing a BART determination for the Boardman Plant. This report was submitted to DEQ on November 2, 2007 and subsequently supplemented in response to dozens of questions posed by various state and federal agencies and interested third parties. The team of experts concluded that if the Boardman Plant were operated through 2040, BART constituted a set of NOx, SO_2 and PM limits reflective of the installation of new low-NOx burners with a modified overfire air system for NOx control and the installation of a semi-dry scrubbing system with fabric filters for SO_2 and PM control. PGE concluded that due to the long lead time and complex engineering challenges the Company needed five years from the date that the Regional Haze SIP is approved in order to engineer, bid, procure, install and start up the SO_2 controls. Federal law authorizes DEQ to allow up to five years from the date EPA approves the Regional Haze SIP. 40 CFR § 51.308(e)(1)(iv).

On December 1, 2008, the Department issued the proposed Boardman Plant BART proposal for public comment. The proposal included new regulations that would require the installation of

[3] The Foster-Wheeler boiler is identified by the U.S. Environmental Protection Agency (EPA) as acid rain program ORISPL code 6106.

[4] 40 CFR § 51.301 defines "in existence on August 7, 1977" as "meaning that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time."

the controls proposed by PGE, but on an expedited schedule. In addition, the Department proposed to require that PGE install selective catalytic reduction ("SCR") in 2017.

PGE submitted comments on DEQ's proposal introducing the concept of shutting down the Boardman Plant boiler before the end of its projected life and, based on the reduced plant life, eliminating some or all post-combustion controls depending on the shutdown date.

On June 19, 2009, the Oregon Environmental Quality Commission ("EQC") adopted the Regional Haze Plan. The Regional Haze Plan includes new regulations (OAR 340-223-0030) imposing NOx, SO_2 and PM limitations reflective of BART and applicable to the Boardman Plant boiler. The NOx regulations require compliance by July 1, 2011 and the SO_2 and PM regulations require compliance by July 1, 2014. The Regional Haze Plan also includes new regulations (OAR 340-223-0040) imposing additional NOx limits reflective of the Reasonable Progress ("RP") requirements of Clean Air Act Section 169A. The RP regulation requires compliance by July 1, 2017. These requirements are summarized below in Table 1.

Table 1
Oregon Regional Haze Plan Requirements for Boardman Plant Boiler

Limit (Assumed Control*)	Installation Deadline	Authority
0.28 lb NOx/MMBtu—30 day rolling average 0.23 lb NOx/MMBtu—annual average (Low-NOx Burners/Overfire Air) **	7/1/2011	BART
0.12 lb SO_2/MMBtu—30 day rolling average 0.012 lb PM/MMBtu—average of source test runs (Semi-Dry Scrubber)	7/1/2014	BART
0.070 lb NOx/MMBtu (SCR)	7/1/2017	Reasonable Progress

* BART constitutes emission limits, not specific controls. The assumed control is provided for illustrative purposes only.
** If combustion controls do result in a showing of compliance by July 1, 2012 and DEQ grants an extension of the compliance deadline to July 1, 2014, the NOx limit changes to 0.23 lb/MMBtu as a 30 day rolling average.

In adopting these BART/RP requirements, the EQC and DEQ acknowledged PGE's request for consideration of a boiler shutdown, but stated that early closure would need to be addressed in future submittals. In Chapter 10 of the Regional Haze Plan, DEQ acknowledged that the cost of future greenhouse gas regulation in context with costs associated with the regional haze SO_2 and NOx controls for the Boardman Plant boiler "could be significant and may require PGE to evaluate cost-benefit factors affecting the future of the Boardman Plant, as part of the Oregon Public Utility Commission Integrated Resource Plan process."[5] In Chapter 12, DEQ also stated that "should PGE determine that the impact and cost of carbon regulations will require the closure of the PGE Boardman Plant, PGE may submit a written request to the Department for a rule change."[6] Thus PGE could petition DEQ for reconsideration of the BART and RP rules if external factors such as carbon regulation would result in early plant closure.

On April 2, 2010, PGE petitioned the EQC to amend OAR 340-223-0030 and -0040 in accordance with the invitation in the Regional Haze Plan. As the Department has acknowledged, DEQ has no authority under the BART requirements to require early closure of a plant. However, a source does have the ability to offer to accept a federally enforceable condition to cease plant operations by a date certain either to avoid BART (by the closure date being no later than 5 years after EPA approval of the Regional Haze Plan into the SIP) or to be accounted for in the BART determination itself. For example, EPA stated in the preamble to the BART implementation rules:

> "With regard to BART-eligible sources not being in operation for the duration of the program, a State, in making BART determinations, is explicitly directed by the CAA to account for the remaining useful life of a source." 70 Fed. Reg. 39125 (July 6, 2005)

The remaining life of the plant is a separate and freestanding criterion as well as a component of the economic impacts analysis in the BART determination process. In its April 2, 2010 petition, PGE proposed to accept a 2020 plant closure date. PGE accompanied the petition with a complete BART analysis that took into account the 2020 closure proposal and concluded that if the Boardman Plant closed in 2020, BART constitutes the use of reduced sulfur coal (for SO_2 control) and new low NOx burners with modified overfire air (for NOx control). BART for particulate was the continued use of the electrostatic precipitator (ESP).

On June 17, 2010, the EQC denied PGE's petition and directed the Department to commence rulemaking to determine other alternatives to the current BART/RP requirements in the Regional

[5] Regional Haze Plan at p. 155.
[6] Regional Haze Plan at p. 202.

Haze Plan. The Department has released a preliminary proposal for informal comment that would provide the following three options in addition to the existing rules:

DEQ BART Revision Proposal Table 2				
	2011 NOx	2014 SO_2	2017 NOx	Closure Date
Existing Rules	LNB/MOFA	SD Scrubber	SCR	2040+
DEQ Option 1	LNB/MOFA/SNCR	SD Scrubber	---	2020
DEQ Option 2	LNB/MOFA/SNCR	DSI	---	2018
DEQ Option 3	LNB/MOFA	---	---	5 years after SIP approval (2016?)

The new alternative options were supported by a draft BART analysis that PGE believes contains errors and incorrect assumptions that materially distort its conclusions. For that reason, PGE is submitting the following comments to identify and correct the errors so that the proposed rule that is placed out on formal notice more accurately reflects the statutory BART process and EPA guidance.

2. Evaluation of Errors in DEQ's BART Analysis

PGE has reviewed DEQ's proposed BART analysis and three additional BART options. While PGE appreciates the Department's willingness to think in terms of alternatives to the current regional haze requirements, PGE believes that there are numerous errors in the Department's BART analysis that result in erroneous conclusions. While our analysis is not yet complete, we are submitting the following comments identifying a number of errors in the Department's analysis.

Plant Closure Assumption is Invalid

One of the most fundamental errors that we believe affects the Department's BART analysis relates to the assumption in Option 2 that the plant will close in any year other than 2020 or 2040, i.e., the end of the Boardman Plant's useful life.[7] As the Department has previously

[7] For ease of reference, 2040 is referred to throughout this document as the end of the Boardman Plant's useful life. However, it is possible that the plant could ultimately operate for a longer period of time—particularly if the controls envisioned by the current BART rules are installed. By using 2040 as a reference point, PGE makes no commitment to cease operating the

(...continued)

acknowledged, Section 169A of the Clean Air Act does not provide DEQ or the EQC the authority to set a closure date for the Boardman Plant. PGE can volunteer to accept a premature closure and then DEQ is required to take that into account in determining BART. EPA stated:

> "[A] State, in making BART determinations, is explicitly directed by the CAA to account for the remaining useful life of a source. Thus, States may factor into their reasonable progress estimates those shutdowns that are required and effected in permit or SIP provisions." 70 Fed. Reg. 39103, 39125 (July 6, 2005).

In considering closure dates other than 2020 and 2040 in establishing BART, DEQ is acting outside of its jurisdictional authority. We note that this is not the case in relation to Option 3 as that option simply states that if PGE does not install BART on Boardman within 5 years after SIP approval, the Boardman Plant must cease operation or face enforcement. This approach is consistent with EPA's clear statement in the 2005 BART rule preamble where it stated:

> "We believe that the CAA mandates consideration of the remaining useful life as a separate factor, and that it is appropriate to consider in the analysis the effects of remaining useful life on costs. We believe that, because the source would not be allowed to operate after the 5-year point without such controls, the option for providing flexibility would not create a loophole for sources. Moreover, any source operating after this point without BART controls in place would be subject to enforcement actions for violating the BART limit. For any source that does not agree to shut down before the 5-year point, the State should identify a specific BART emission limit that would apply after this point in time." 70 Fed. Reg. at 39127.

For that reason, we request that DEQ not propose a BART option that anticipates a 2018 closure of the Boardman Plant. PGE has never offered such a closure date and DEQ lacks legal authority to impose such a requirement.

(...continued)
Boardman Plant in 2040. Any decision as to the useful life of the Boardman Plant would need to be reviewed by the Oregon Public Utilities Commission.

The Department Failed to Identify Technically Feasible Controls

In its April 2, 2010 BART analysis, PGE identified the use of reduced sulfur American coal as an interim control for consideration as BART. In its draft BART analysis, the Department added two additional interim technologies, DSI and the use of Indonesian coal. We do not contest that these two technologies should be listed in Step 1 of the BART analysis as "available retrofit control technologies." However, both technologies should be eliminated in the second stage as not being technically feasible.

The importation of Indonesian coal is technically infeasible as an interim BART control. As DEQ acknowledges in its second bullet on page 20 of the Department's draft BART analysis, it would be infeasible for PGE to import Indonesian coal to the west coast of the U.S. There are no existing port facilities that could accommodate these shipments. Setting aside the profound policy reasons why the Department should not be requiring Oregon consumers to pay for the importation of coal from a country with a questionable history of mine reclamation, worker safety and environmental protections (let alone a country that the U.S. government has labeled a haven for terrorism),[8] it is technically infeasible to actually transport the coal into any west coast port and, from there, to the Boardman Plant.[9] In addition, managing shipments around the Indonesian monsoon season is a real issue, which has resulted in price increases and curtailment of coal supply under supply contract *force majeure* provisions.[10] Lastly, there is no demonstration that the Indonesian coal is of acceptable quality to even be burned in the Boardman Plant boiler. Therefore, the use of Indonesian coal should be removed from the possible interim control options at Step 2, based on technical infeasibility.

Similarly, there is no basis for concluding that DSI, as proposed, is technically feasible. EPA stated in its 2005 BART rule preamble what was required in order for a technology to be considered technically feasible. Specifically, EPA stated:

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[8] See, http://travel.state.gov/travel/cis_pa_tw/cis/cis_2052.html#safety

[9] We note that the two plants identified by DEQ as having utilized imported Indonesian coal are located on the east coast and have associated importation facilities that are not available in the Western U.S.

[10] See, e.g., http://www.thejakartaglobe.com/business/indonesian-coal-prices-up-as-rain-curbs-supply/372199; also see, http://www.reuters.com/article/idUSJAK42062020100427

> "Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: ''availability'' and ''applicability.'' As explained in more detail below, a technology is considered ''available'' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is ''applicable'' if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible. 70 Fed. Reg. at 39165.

It is clear that DSI is not an applicable technology, as that term is defined by EPA. As the Department acknowledges in its BART analysis,

> "DSI has been demonstrated in practice on smaller coal-fired boilers (<100 MW). It has not been demonstrated on larger boilers..." DEQ Draft BART Analysis at page 6.

The Department seeks to distance itself from this acknowledgement by suggesting that DSI has never been installed on a boiler as large as that at the Boardman Plant because nobody has ever wanted to. However, that does not change the fact that there is no demonstration project showing that DSI can be used on a long term basis for a boiler the size of the Boardman Plant boiler. Absent such a demonstration, DEQ cannot unilaterally impose DSI on the Boardman Plant as BART. By contrast, PGE could agree to serve as a demonstration project for DSI, but would only be able to do so if appropriate alternative emission limits were included within the rule to protect PGE if DSI turned out not to be cost-effective, compatible with the mercury controls, permittable, or able to achieve significant levels of SO_2 control.

An additional reason not considered by DEQ in its BART analysis is whether under recent regulatory changes a DSI system is permittable. Even if DSI were assumed to be able to achieve the SO_2 reductions suggested by the Department, the technology is not technically feasible if it would be impossible for PGE to obtain a permit to install and operate the technology. As the Department has acknowledged, EPA will be withdrawing its PM_{10} surrogacy policy that has allowed sources to be permitted under PSD without having to evaluate $PM_{2.5}$. Therefore, DEQ is requesting that the EQC adopt as an emergency rule at its August meeting provisions that would establish the baseline year for $PM_{2.5}$ as 2007 or 2006 (unless a prior year can be established as better representing normal conditions), a 10 ton/year significant emission rate, a $PM_{2.5}$ PSD increment and a $PM_{2.5}$ significant impact level. Under these regulations, the installation of DSI would trigger PSD for $PM_{2.5}$ if it resulted in PGE requiring a plant site emission limit ("PSEL") in excess of its 2006/2007 actual $PM_{2.5}$ emission rate by 10 tons per year or more. PGE has estimated that DSI would require the addition of approximately 4 tons/hour of reagent powder into the boiler exhaust upstream of the ESP. Assuming 8,000 hours of operation per year, this would equate to 32,000 tons of particulate being introduced into the exhaust gas annually. The additional burden imposed on the particulate control device (ESP) could cause it to lose efficiency at collecting the smaller particles, thus likely resulting in an increase in $PM_{2.5}$ emissions in excess of 10 tons per year.[11] PGE's preliminary modeling indicates that at the anticipated level of increased $PM_{2.5}$ emissions associated with DSI, the Boardman Plant would cause a $PM_{2.5}$ increment and/or NAAQS exceedance thus making the DSI technology unpermittable. Because it could not be lawfully operated, the DSI technology is not technically feasible. We note that this aspect of DSI operation would not have been identified in relation to the small boilers that have employed the technology for two reasons. First, the smaller boilers would have had a proportionately smaller level of $PM_{2.5}$ emissions. Second, any boiler that already has a permit would have obtained it while EPA's PM_{10} surrogate policy was still in effect. Therefore, these boilers would not have had to evaluate $PM_{2.5}$ impacts. As a result, the previous permitting of the smaller boilers is not a basis for concluding that the Boardman Plant boiler could pass permitting review for DSI installation.

DSI by itself is similarly not technically feasible as it could not be installed and achieve compliance with the applicable New Source Performance Standard ("NSPS"). The applicable boiler NSPS, Subpart Da, imposes a particulate limit of 0.015 lb/MMBtu heat input. 40 CFR § 60.42Da(c)(2). This limit is triggered by modifications that occur after February 28, 2005. A modification occurs if there is physical change that results in a statistically significant change in particulate emissions. 40 CFR § 60.14. If PGE installed DSI, the evidence overwhelmingly shows that a statistically significant increase in the hourly capacity to emit particulate would

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[11] By means of reference, Section 7.2 of the BART analysis states that without DSI approximately 66 percent of the Boardman Plant's particulate emissions are $PM_{2.5}$. This equates to 275 tons per year of $PM_{2.5}$ emissions in the baseline period based on the emission rates identified in Table 2-3. A 3.5 percent increase in $PM_{2.5}$ emissions as a result of adding over 32,000 tons per year of fine particulate (i.e., adsorbent) into the stack exhaust appears likely to result in a 10 ton per year increase in $PM_{2.5}$.

occur. Therefore, PGE would be required to comply with the 0.015 lb/MMBtu limit, which the ESP would be incapable of doing with 4 tons per hour of reagent being added to the inlet gas. Therefore, DSI could not be installed and maintain compliance with the Subpart Da NSPS limits. Therefore, this technology cannot be considered technically feasible.

For the reasons outlined above, both the importation of Indonesian coal and the installation of DSI should be eliminated at Step 2 of the BART analysis.

DEQ Wrongly Evaluated the Cost Impacts of Imported Indonesian Coal and DSI

While PGE believes that imported Indonesian coal and DSI are both technically infeasible, we have prepared comments on the defects in the cost impact analysis as if the technologies were technically feasible. To be perfectly clear, DEQ and other readers of these comments should not conclude that because we are making these comments on cost impacts that we consider either technology technically feasible.

Imported Indonesian Coal is Not Cost-Effective Even if It Were Technically Feasible

Imported Indonesian coal is unequivocally not cost-effective. As noted above, there are no receiving facilities in the western U.S. that would be capable of receiving, unloading and reloading the coal into unit trains. Therefore, were imported Indonesian coal considered technically feasible, it would be necessary to construct an entire unloading and reloading facility, including storage structures, capable of handling the volume of coal needed to fuel the Boardman Plant. Land would either have to be acquired or leased to facilitate this new infrastructure. All this would cost hundreds of millions of dollars. PGE would further need to secure rights over the rail lines that connect the deepwater port capable of handling a coal laden ship to Boardman. This would involve additional costs. Constructing these facilities and bringing them on line could likely not be completed by 2014 given the land acquisition, permitting and siting processes that would be involved. In addition, PGE estimates the initial capital cost would be in exess of $100 million and the annual operational costs would be $275-$300 million. The biggest cost component in the annual operational costs is the delivery of the Indonesian coal, which is over 3.5 times higher than domestic options. It may also be necessary, given the potential for political instability in Indonesia, to stockpile considerable amounts of coal in case of interruption in supply due to terrorism, labor unrest or political upheaval. This introduces both a direct operating cost as well as a significant risk which imposes an additional cost of replacement power if the Indonesian mine cannot deliver as promised. None of these potential costs have been included in the operational cost amounts described above. It is extraordinarily speculative to think that the Oregon Public Utilities Commission would consider such an investment and fueling approach to be prudent and in the best interests of PGE's customers. In short, DEQ's BART analysis does not incorporate the extreme economic impacts associated with importing Indonesian coal. Including these costs demonstrates that even if the importation of Indonesian coal were technically feasible, that the direct and incremental cost-effectiveness of the emission reductions would be too extreme to consider this option BART.

<u>DSI is Not Cost-Effective Even if It Were Technically Feasible</u>

Similarly there are fundamental flaws in DEQ's cost-effectiveness analysis of DSI. The Department's BART analysis assumed that the installation of DSI would require "only" a $52.2 million investment and an annual operational cost of only $2.6 million. However, this cost fails to take into account the fact that the installation of DSI could trigger PSD for $PM_{2.5}$. As a result, the Department's BART analysis fails to identify the costs associated with PSD compliance. As a result, even if DSI were considered technically feasible and were capable of being permitted, the costs associated with maintaining $PM_{2.5}$ emissions below the increment and NAAQS could render the technology not cost-effective.

<u>Semi-Dry Scrubbing Cost-Effectiveness Numbers in DEQ BART Analysis Understate True Cost</u>

Since the adoption of the Regional Haze Plan, PGE engaged Sargent & Lundy ("S&L"), an internationally recognized engineering company with extensive expertise in designing and contracting semi-dry scrubbing systems for coal-fired power plants. S&L has assembled a new detailed cost analysis for the construction and operation of a semi-dry scrubbing system for the Boardman Plant. Based on S&L's assessment, the true cost of controlling SO_2 emissions with a semi-dry scrubber are higher than what was identified in the prior BART analysis by approximately 30 percent. If the capital and operating costs are adjusted, then the Department's estimate of direct cost-effectiveness would increase to over $6,500/ton and incremental cost-effectiveness would increase to near $9,000/ton. Of course, as discussed further below, these costs as expressed in dollars per ton, while being singularly relevant in the BART context, do not show the true cost effectiveness with respect to PGE's customers. Installing a very expensive semi-dry scrubber for six and a half years and then shutting it down is not in the best interests of customers, and does not achieve the balance of environmental benefit, maintaining the reliability of the electric power grid, and reducing the economic impact of closure to employees at the plant and the communities in which they live and work.

The Department's BART Analysis Fails to Account for Replacement Resource Cost

The Department's BART analysis is also flawed in that it fails to account for the cost to PGE and its customers of the loss of the Boardman Plant. In a typical BART analysis, DEQ would account exclusively for the capital and operating cost of controls and divide that number by the avoided emissions to calculate the cost of control. However, what PGE proposed in its April 2, 2010 BART analysis was anything but a typical BART approach. Instead, PGE proposed to shut the Boardman Plant down at least 20 years before the end of its operating life. The Boardman Plant is one of the lowest cost thermal resources in PGE's portfolio. By agreeing to shut the plant down at least 20 years early, PGE is taking on a significant additional cost and foregoing a valuable opportunity. There is a cost associated with relinquishing Boardman's low-cost baseload generation capacity that must be accounted for as PGE must continue to supply the amount of electricity that its customers demand.

The Department's cost-effectiveness evaluation of its Option 2 must recognize the costs associated with premature retirement of the boiler. These include the incremental replacement costs associated with closing the Boardman plant sooner than it would otherwise be closed. There are considerable costs that DEQ has not taken into account in evaluating the cost effectiveness of the premature closure options. In addition, in evaluating the cost of a BART option that includes a premature shutdown for a regulated utility, such as PGE, the agency cannot look at just the costs associated with the source under scrutiny. PGE is required by law to ensure that whenever one of its customers needs electricity, that power is available.[12] PGE does not have the option of telling customers that it is exiting the market and they must find other means of satisfying their electricity needs. PGE does not have excess generating capacity and is actually facing potential supply shortages even without the Boardman Plant closing. As a result, the closure of any generation asset must include the cost of finding a replacement. To replace that power, PGE's lowest cost and lowest risk option may be to spend millions of dollars on a natural gas fired power plant.[13] Dispatch costs on a megawatt-hour basis may also be significantly higher for a natural gas replacement resource replacing Boardman. The DEQ BART analysis already recognizes additional replacement power costs of $50 per megawatt-hour, which could result in excess of $200 million of dollars of additional costs on an annual

[12] ORS 757.020.

[13] Preliminary estimates are approximately $700-800 million in 2010 dollars for a replacement natural gas plant constructed in 2021.

basis. Nowhere does the Department reflect these direct costs of closure in its cost-effectiveness analysis.

The Department should take into account the direct costs associated with the premature closure of the Boardman Plant as well as the replacement resource needed to backfill the Boardman Plant's generation after closure, and recognize that the use of reduced sulfur coal through 2020 in conjunction with low NOx burners and modified overfire air constitutes BART. If it were not for PGE's commitment to close the Boardman Plant 20 years early, the additional costs of replacement generation to cover the Boardman Plant's output would not be incurred. Therefore, there is a direct but-for causation that requires that these replacement costs be factored into any assessment of the cost-effectiveness of control scenarios that involve the premature closure of the Boardman Plant. PGE is proposing to incur these costs so long as the capital costs associated with the final years of operation are not excessive. However, if DEQ adds the $350 million capital cost and $9 million per year operating cost of semi-dry scrubbers to the costs associate with operating the Boardman Plant through 2020, then this option far exceeds any cost-effectiveness threshold.

Integrated Resource Planning (IRP) analyses conducted under the Oregon Public Utility Commission (OPUC) show that it would be ridiculous for PGE to invest that much of its customers' money in controls that would only run for 6.5 years. The reason that the Department's analysis does not comport with the analysis before the OPUC is that DEQ has failed to account for all of the costs in evaluating its Option 1. When the additional costs associated with closing the Boardman Plant and accelerating a replacement source of electricity is included in the cost, as it must be, then the cost of Option 1 far exceeds $10,000/ton. This more complex evaluation of the control/closure costs associated with the Boardman Plant is being evaluated in PGE's IRP. The reason that the IRP analysis generates the conclusion that the most prudent approach is to operate the Boardman Plant through 2020 using reduced sulfur coal as proposed by PGE below is because it takes into account the true cost of the alternative options.

Including the cost of both the controls and the replacement asset when evaluating the cost-effectiveness of an option is a concept familiar to everyone. If you have an older but reliable car you will not just evaluate the cost of a repair when determining whether to proceed with an investment. If the engine fails on a car that you had planned to drive for 6 more years and you need to evaluate whether to pay for the $1,000 fix that will give the car 3 more years of life or the $2,000 fix that will allow the car to run the full 6 years of its remaining life, you would not say that the two options are equal because they each result in a cost of $333 per year of vehicle life. You would necessarily have to account for the costs associated with accelerating the replacement of the vehicle. This includes the large capital investment in the new vehicle. Nobody would think for a moment that the only consideration was the cost of the repair itself. Likewise, in evaluating the cost-effectiveness of an option that includes shuttering the Boardman Plant before the end of its useful life, DEQ must take into account the additional costs associated with accelerating the replacement of a replacement resource. When those costs are added in the semi-dry scrubbing option with 2020 closure which DEQ already refers to as only "marginally cost effective" then it is clear that Option 1 is actually not cost-effective. Similarly, when the replacement costs as well as the additional control and permitting costs associated with DSI are considered, as they must be, then that cost also exceeds the cost-effectiveness threshold chosen by DEQ ($7300/ton), even if one considers DSI technically feasible.

The Department's Cost-Effectiveness Threshold is Too High

The Department's choice of a $7,300/ton cost-effectiveness threshold is excessively high and improperly distorts the BART analysis. The Department identified a $7,300/ton cost-effectiveness threshold in the BART analysis but offers no legitimate basis for this figure. Other BART analyses across the country have employed significantly lower cost-effectiveness thresholds. In discussions with DEQ, they have identified the basis of the $7,300/ton cost-effectiveness threshold as the BART determination for a Minnesota facility. However, as the Department acknowledges at page 18 of its BART analysis, most other BART analyses apply a cost-effectiveness threshold of $3,000/ton and the Minnesota BART analysis that DEQ relied on was changed prior to finalization and applies a cost-effectiveness threshold of less than $4,000/ton. Thus the Department's own BART analysis documents support that it lacks a basis for the $7,300/ton cost-effectiveness threshold it is applying. The Department also points to a preliminary assessment from New Mexico where the permitting authority said that for a power plant affecting 16 Class I areas that the appropriate cost-effectiveness threshold was between $5,946 and $7,398. By the Department's own logic the New Mexico facility (San Juan) should have a higher cost-effectiveness threshold as compared to the Boardman Plant because the New Mexico plant affects more Class I areas than the Boardman Plant. However, the Department mischaracterizes the San Juan BART analysis as if it were complete when it is currently a proposed determination and subject to further public review and comment . Also, the cost-effectiveness numbers that DEQ references for the San Juan BART analysis were for NOx and not for SO_2. The preliminary assessment of a different state in relation to a facility with a much bigger footprint that includes 6 national parks is not a basis for DEQ to adopt the New Mexico authority's work in progress as binding in Oregon. The Department fails to identify a single final BART determination that relied on a cost-effectiveness threshold as high as the one it is proposing.

DEQ Failed to Adequately Take Into Account Incremental Costs

DEQ's BART analysis is also inconsistent with the agency's legal authority in that it fails to adequately take into consideration the incremental cost of the technologies that it is proposing in Option 1. The BART rules that DEQ stated it was following in developing the Boardman Plant BART analysis specify that both the direct cost-effectiveness and the incremental cost-effectiveness must be evaluated. Nonetheless, the Department ignores the incremental cost-effectiveness in making its BART determination. Even if one assumed that the costs evaluated by the Department were accurate (and we demonstrated above that they are not) and the Department's cost-effectiveness threshold is appropriate (and we demonstrated above that it is too high), the incremental cost-effectiveness for Option 1 is excessive. The Department openly acknowledges this in its BART report for the new options, but then appears to ignore it.[14] As adjusted by the updated price data from S&L showing a 30% increase in price, the correct incremental cost is near $9,000/ton, which is significantly higher than the Department's $7,300/ton threshold. Ignoring the excessiveness of this cost is clearly inconsistent with the process established by EPA and accepted by DEQ for establishing what constitutes BART. The Department should revise its BART analysis to reflect its own process and thereby eliminate semi-dry scrubbing as BART under Option 1.

DEQ Failed to Account for the Energy and Environmental Impacts of DSI

The Department's BART analysis is flawed in that it identifies that DSI could result in environmental impacts and yet fails to fully explain or in any way account for those in reaching its Option 2 BART determination. As the Department openly recognizes in multiple places within its BART analysis (e.g., Table 11), the use of DSI likely will result in an increase in particulate emissions. However, the Department makes no attempt to estimate the extent of this impact. As we explain above, the emissions increase associated with DSI is significant and will most certainly result in the Boardman Plant having to undergo PSD for $PM_{2.5}$. Similarly, the Department's BART analysis documents that the use of DSI will impair the efficiency of the Boardman Plant's mercury controls. Again, there is no attempt to quantify this impact or to explain why it is acceptable to require a technology that could result in increased mercury

[14] *See* Draft Boardman Power Plant BART Report at page 11.

emissions. The Department must quantify and take into account in deciding to require DSI as a component of Option 2 the potential ramifications from the requirement to use DSI at the Boardman Plant.

Visibility Assessment Fails to Account for the Benefits of Early Closure

The Department's assessment of the visibility improvements associated with each option is flawed in that it fails to take into account the years of visibility improvement associated with premature closure. The table provided at page iv of the Department's BART analysis identifies that its Option 1 would result in an additional reduction of 7,700 tons of visibility impairing pollutants and that Option 2 would result in an additional reduction of 14,900 tons of visibility impairing pollutants. However, nowhere in its analysis does the Department make reference to the tens of thousands of tons of visibility impairing pollutants that the environment will not see if PGE is allowed to shut the Boardman Plant in 2020. Even if the Boardman Plant installs semi-dry scrubbers, twenty years of SO_2 emissions amounts to over 58,000 tons of SO_2. The Department completely fails to take into account the enormous reduction in emissions associated with early closure. This is a fundamental flaw in the BART analysis. When these reductions are properly taken into account a 2020 closure option with the implementation of reduced sulfur coal, SNCR, and low NOx burners and modified overfire air as discussed below is clearly the best BART option.

DEQ Failed to Conduct a Complete Modeling Analysis for its Proposed Options

The Department has no basis to support its Option 1 and Option 2 BART proposals in the absence of having performed complete visibility modeling for those options. One of the bedrocks of the BART process is to assess the visibility improvements associated with each option under consideration. In developing its BART alternatives, the Department failed to conduct a complete modeling analysis and the limited analysis that it did perform contains errors.

The Department's BART Assessment Fails to Take into Account The Rate of Progress at the Affected Class I Areas

In preparing its BART analysis, the Department failed to consider where the Class I areas are in relation to their uniform rates of progress (the "glide paths") and how the options will accelerate compliance with those options. Fourteen Class I areas are within 300 km of the Boardman Plant. Consistent with the statutory goal of reducing the worst haze conditions to natural levels by 2064, glide paths have been developed for each Class I area. This allows comparison of the projected progress towards the statutory goal against the uniform rate of progress that defines the glide path. PGE acknowledges that to some extent BART exists independent of the glide paths in that BART is required regardless of the progress towards the statutory goal. However, if a Class I area has projected impacts for the next several decades that will be far in excess of its glide path, then it may be appropriate to impose a higher cost-effectiveness threshold or otherwise hold a source impacting that Class I to a higher standard. On the other hand, where the Class I area is on course to achieving its uniform rate of progress goals over the next ten years, then a lower cost-effectiveness threshold is appropriate. With any option that requires the premature closure of the Boardman Plant, there will be a substantial movement of the nearby Class I areas towards the statutory visibility goal.

A BART Determination Requiring Use of Reduced Sulfur Coal, Low NOx Burners, Modified Overfire Air and 2020 Closure is Approvable by EPA

The Department has inaccurately suggested on multiple occasions that reduced sulfur coal, low NOx burners, modified overfire air and 2020 closure is not a BART determination that could be approved by EPA. This statement is incorrect. Three reasons were given for why such a BART determination could not be approved by EPA: (1) Lack of enforceability of a closure requirement, (2) Absence of interim control measures, and (3) Excessive cumulative impacts. We address each of these three objections below.

Enforceability of Closure Requirement

As the Department acknowledges in its BART options analysis, there is no basis for the argument that a Boardman Plant closure date could not be made enforceable. DEQ's Options 1, 2 and 3 plus PGE's proposed 2020 solution discussed below all contemplate the early closure of the Boardman Plant and if PGE chooses to accept such an early closure, all contemplate effectuation by a regulatory requirement. Such a requirement would, of course, be an enforceable permit condition, subject to penalties. So long as such a requirement is included in the State Implementation Plan there is absolutely no credibility to an argument that such a requirement is not both state and federally enforceable.

Absence of Interim Controls

PGE acknowledges that any BART determination that rests upon premature plant closure must also include an analysis of whether any interim controls can be imposed, consistent with BART, to limit emissions prior to the shutdown. For this reason, in its April 2, 2010 BART analysis

PGE included an analysis of interim controls. SO_2 emissions are directly related to sulfur content in the coal delivered to PGE. PGE is currently permitted to emit up to 1.2 lb SO_2/MMBtu heat input. Coal sulfur content varies year-to-year, with the SO_2 emissions frequently running significantly higher than the baseline period defined for the BART analysis. Therefore, PGE evaluated and ultimately proposed the use of reduced sulfur coal thereby decreasing the allowable SO_2 emission rate by 50 percent.

The Department inappropriately dismissed PGE's proposed reduction of the SO_2 emission rate from 1.2 lb/MMBtu to 0.6 lb MMBtu. In its proposed BART analysis, the Department states that *as compared to the baseline period* the implementation of reduced sulfur coal would "only" achieve a 0.43 dV of visibility improvement. This is an inaccurate statement for two reasons. First, the maximum reduction in visibility impacts as a result of shifting to reduced sulfur coal as compared to the baseline period is 0.50 dV, occurring at Mt Hood (an 18.6 percent improvement). This is a significant improvement. However, this understates the benefits of reduced sulfur coal in that there are benefits across all 14 Class I areas evaluated, as well as the Columbia Gorge. PGE objects to the use of cumulative impacts as an inaccurate and misleading means of evaluating visibility impacts or benefits. However, if one were to sum the visibility improvements across the fourteen Class I areas, it would amount to 3.85 dV in visibility improvement. Second, evaluating SO_2 reductions in relation to the baseline modeling period distorts the overall benefits of reduced sulfur coal. Currently PGE can and does emit SO_2 at levels significantly higher than the visibility assessment baseline used by DEQ while operating in compliance with its air permit. Reducing the SO_2 permit limit to 0.6lbs/MMBTu is significantly lower than the industry standard and it could restrict the coal available to PGE and increase the price at which the fuel can be obtained. Dismissing the coal restriction as not being an interim control because lower sulfur coal happened to have been utilized during the BART baseline period is in error. PGE 's only control of the sulfur content in supply contracts is to specify a target and maximum level. During the BART baseline period, the coal deliveries varied based on what happened to be delivered by the mines, capped by a sulfur level of 1.2 lbs/MMBtu. The department should consider the fact that coal is not a refined fuel that can be delivered at a specific sulfur level. Reducing a permit limit and requiring Boardman to limit the type of coal combusted in the boiler is a real reduction, and a method of SO_2 control that should be recognized as a robust interim control measure.

The Department, in its BART analysis, considered two additional interim controls, the importation of Indonesian coal and the use of DSI. As explained above and acknowledged by DEQ in its BART analysis, there is no rational basis for requiring the importation of coal from Indonesia. As is also explained in detail above, the Department failed to account for potential cost, permitting issues, and technical feasibility associated with the use of DSI. When these are taken into account, then the use of DSI is swiftly eliminated from contention as an interim control as well. In the absence of any other viable interim controls, there is no basis for suggesting that PGE did not consider all viable interim measures and that PGE's proposed interim control is inadequate.

Excessive Cumulative Impacts

The final, and equally indefensible, suggestion for why EPA would not find PGE's April 2, 2010 BART analysis "approvable" was that it did not take into account the cumulative impacts across all Class I areas. This approach was used by DEQ in its BART analysis. The clear wording of the Clean Air Act as well as longstanding EPA and DEQ precedent weigh against this type of an assessment. For decades, EPA and DEQ have been performing visibility assessments. Each of these assessments has been performed on a Class I by Class I area basis. DEQ has never applied a cumulative assessment that aggregated all impacts across all Class I areas within the radius of impact. Making such a profound change at this time from an established agency means of addressing visibility may require rulemaking on DEQ's part.

The cumulative approach that DEQ is suggesting also ignores the reality of how human beings perceive visibility. No single individual would be able to perceive visibility impacts across all 14 Class I areas within the 300 km radius of impact. Yet the cumulative approach essentially assumes that such simultaneous observation of visibility impacts in multiple Class I areas can and does occur. Furthermore, the cumulative approach distorts the temporal element of visibility impact assessment. On any given day the Boardman Plant will impact only a subset of the Class I areas and such impacts change day to day and even over the course of the day. Aggregating the impacts as DEQ suggests both distorts and exaggerates the true impact of the Boardman Plant. Conversely, this approach overstates the benefits associated with particular control technologies. The truth of this statement is best shown by two examples. If a control achieved a tenth of a deciview of improvement at ten different Class I areas, the cumulative evaluation approach would suggest that a significant improvement resulted. However, a tenth of a deciview of improvement is far below the level that the human eye can detect. Second, under the cumulative approach the benefits would double if a single Class I area were divided into two. Similarly, improvements achieved at Goat Rocks Wilderness area and Mt Rainier National Park would be counted twice even though the reduction at one necessarily carries with it the reduction at the other due to their proximity in relation to the Boardman Plant. Such an approach makes no sense and generates bad policy decisions. This approach is even worse when developed into a cumulative dollars per deciview evaluation approach. Such an approach arbitrarily inflates the projected visibility improvements and underrepresents the costs associated with any improvement.

EPA has generally expressed concerns about relying too heavily on the "dollars per deciview" metric in making a BART determination. The 2005 BART guidelines acknowledge that this is one means of evaluating BART options. However, as EPA has previously stated, "given the significant difficulties in developing a meaningful method for calculating $/dv, EPA does not recommend its use as the sole factor in making a BART determination and would likely not approve a SIP based on that basis." EPA Region 7 Letter to Nebraska DEQ; June 26, 2009. DEQ is acting inconsistently with this guidance by overly relying on the approach of evaluating BART options based on cumulative impacts and a dollars per deciview metric.

3. PGE's Proposed Resolution

For the reasons stated above, the Department's BART analysis is fundamentally flawed and that neither Option 1 nor Option 2 can be considered BART. When the Department's BART analysis is corrected and the true costs of the different options are evaluated, it is clear that operation on reduced sulfur coal, low-NOx burners, modified overfire air and SNCR through 2020 constitutes BART. However, while DSI cannot be required as BART without adequate consideration of its cost-effectiveness, and due to its likely inability to be permitted at the level of operation anticipated by DEQ and the absence of long term experience with the technology on boilers similar to the Boardman Plant boiler, PGE is willing to commit to a pilot study of the technology. Based on that pilot study, PGE would determine the highest level of reagent injection that could occur in conjunction with the other controls without causing a significant increase in $PM_{2.5}$ emissions and without impairing the ability to reduce mercury emissions by at least 90 percent. Contingent on the results of the pilot testing, PGE would commit to meeting a 0.4 lb SO_2/MMBtu limit through 2020 using DSI. If this option is considered BART, DEQ would need to provide a procedure for establishing an alternative SO_2 limit if PGE's pilot testing demonstrated that operation of DSI could not reach 0.4 lb SO_2/MMBtu, when operating in conjunction with SNCR and the mercury controls, without resulting in an increase in the hourly capacity to emit PM or triggering PSD for $PM_{2.5}$ (assuming the same level of operation currently reflected in the Boardman Plant's plant site emission limits). If this showing can be made, then the 0.4 lb SO_2/MMBtu would apply starting on July 1, 2014. If the showing cannot be made, then DEQ would provide a mechanism for establishing an alternative BART SO_2 limit based on the pilot test at the highest level of control that can reliably be achieved without increasing the hourly capacity to emit PM or triggering PSD (but no higher than 0.6 lb/MMBtu). The analysis of the pilot test results and any procedure for establishing an alternative BART SO_2 limit would be based on the Boardman Plant operating at the same levels currently reflected in the Boardman Plant's plant site emission limits. Closure, in 2020, would be enforced through a state and federally enforceable permit condition, subject to penalties for noncompliance.

4. Conclusion

PGE appreciates the opportunity to comment on the Department's BART determination in advance of the Fiscal Impacts Advisory Committee meeting. Any requirement that the Company install hundreds of millions of dollars worth of control equipment and then recover those costs over a short remaining plant life and then pay for replacement generation thereafter has a profound impact on our customers. At a time when our customers, and Oregon itself, struggle to manage through the Great Recession and any increase in rates is greeted with concern, we believe that it defies common sense to require an investment that could reach $400 million and then require that the plant shut down at least 22 years early. Such an approach does not appear prudent and would be viewed by small and large business owners, commercial entities and residential customers as a significant and unreasonable impact. Emphasizing again what we stated above, if an acceptable amendment to the 2009 Regional Haze rules cannot be achieved, our most responsible course of action remains full implementation of controls and continued operation of the plant to serve our customers through at least 2040. As unfortunate and unnecessary an outcome as this may be, we believe that it will still be the best plan available to us if the other options described by DEQ are carried through to the final rule amendments as drafted. Therefore, we believe the best approach is to proceed with a BART determination that matches the elements described in Section 3 above.

LC 48

PGE's 2009 Integrated Resource Plan

Attachment 2

Sierra Club Press Materials
(Handwritten notations made by PGE)

View a web version of this email.

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Contact:
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2020 ok for L.A

Sierra Club Cheers L.A. Coal-Free Commitment

Los Angeles, CA – Los Angeles Mayor Antonio Villaraigosa's announced today that the city would eliminate the use of coal by 2020. L.A. will replace the 40% of its power currently generated by coal with renewable energy. Under the plan the city will receive 20% of its energy from renewable sources by next year, and 40% by 2020.

The Los Angeles Department of Water and Power (LADWP) is the nation's largest municipal utility with over one million customers.

"We applaud Mayor Villaraigosa's bold decision to move Los Angeles beyond coal. The decision to replace coal with cleaner energy alternatives is key to boosting job creation and economic growth," said Bruce Nilles, Director of the Sierra Club's Beyond Coal Campaign.

"Investing wisely, at the city, state and federal levels, is essential in these tough economic times; we must put our money where we will get the most in return. The development and production of renewable energy will lead to job growth and economic improvement without the health and environmental drawbacks of continued investment in dirty coal," continued Nilles.

Bill Corcoran, Senior Regional Representative in Los Angeles added, "Mayor Villaraigosa's commitment to eliminate coal by 2020 creates an enormous economic development opportunity for the city. Instead of sending millions in ratepayer dollars every year to pay for coal plants in Utah and Arizona, we will invest that money here in Los Angeles and in California. Work making our buildings more efficient can't be outsourced to China."

"By maximizing energy efficiency and conservation at the same time that the city turns to renewable energy, the city can get off dirty coal while minimizing utility bill increases. The Sierra Club looks forward to working with the utility to identify and adopt the best technologies and financing opportunities to realize the mayor's vision," said Corcoran.

The coal power currently used by Los Angeles comes almost entirely from two large power plants, the Intermountain Power Project in Utah and the Navajo plant in Arizona. The Navajo plant contributes significant air pollution to Grand Canyon National Park.

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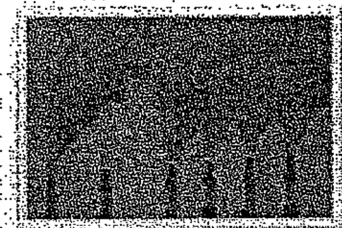
Pasadena Beyond Coal

Sierra Club Beyond Coal Campaign endorses Coal-Free Pasadena



The Renewable Energy Accountability Project (REAP) has launched the "Pasadena End Coal Electricity Educational Project," which will educate people about the hazards and costs of mining and burning coal for electricity.

We support a dialogue in Pasadena about the harmful effects of coal-fired electricity. The best science tells us that we must swiftly reduce and eliminate coal plant emissions to moderate the severity of climate change. Coal mining and combustion harm the land, pollute our water, and
intensify global warming.

The Sierra Club, as part of its national focus on climate change, has made the elimination of dirty coal-fired power plants a priority. Increased energy efficiency and cleaner sources of energy can replace coal and benefit local economies. We believe that strong leadership is needed to achieve this goal.

That leadership must come from all parts of our society. Increasingly, Americans recognize the risks of coal. According to a recent public opinion survey conducted by REAP, 68% of Pasadena residents support their city divesting its long-term coal power purchase agreements. That support reflects Pasadena's legacy of environmental leadership. The 2009 Integrated Resource Plan adopted by the City of Pasadena in March puts Pasadena on the path toward cleaner energy by having [illegible] of the city's electricity come from renewable sources by 2020 and reducing greenhouse gas emissions by [illegible]. Coal would account for 25% of electricity sales by Pasadena Water and Power by 2020, and its use would continue through at least 2027. Phasing out coal power more quickly will require a strong commitment from city officials, leaders, and residents.

The "Pasadena End Coal Electricity Educational Project" will further public understanding of the true price of coal. The Sierra Club believes it is time to move beyond coal and toward a cleaner future that invests energy dollars as locally as possible.

Take Action!

Sierra Endorses plan
that continues coal
use through 2027.
Coal ok for
Pasadena

Coal Free Commitment

The Pasadena End Dirty Coal Electricity Education Project will urge Pasadena to more aggressively phase-out its owner

ship interests, and 18 year contracts, for out-of-state coal generated electricity.

Although Pasadena's 2009 Integrated Resource Plan seeks to reduce current coal electricity usage to 25% by 2020, clearer and more consistent annual progress needs to be made.

POWER CONTENT LABEL
First Quarter 2009

ENERGY RESOURCES	2009 PWP POWER MIX* (projected)	2009 PWP GREEN POWER MIX** (projected)	2007 CA POWER MIX*** (for comparison)
Eligible Renewable	11%	100%	10%
• Biomass & Waste	8%	0%	<1%
• Geothermal	2%	0%	2%

Sierra Club Online Community

Get the Sierra Club Insider, our email newsletter. News, green lifestyle tips, and ways to take action on Beyond Coal and more: right to your inbox, twice a month.

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LONE STAR CHAPTER

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- Ecosystems
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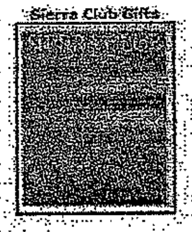


Solar Panels

Health Impacts from Texas Coal Plant Pollution

Texas Coal Plants Fact Sheet

Lone Star Chapter Sierra Club

For Immediate Release: Monday, November 9, 2009

For more information, contact: Cyrus Reed, Sierra Club, 512-740-4086 or 477-1729
Donna Hoffman, Sierra Club, 512-289-5776,
Matt Johnson, Public Citizen, 512-477-1155

Austin Generation Task Force Recommends Increasing Energy Efficiency and On-site Renewable Power and Further Reducing Carbon Dioxide

Rallies, Bike Rides and Hikes for Clean Power, Green Jobs, and Clean Air ask EPA to stop TCEQ from Permitting New Coal Plants

Majority endorses Austin Generation Plan with Increased Commitment to End Coal Addiction

(Austin) The nine-member Austin Generation Resource Planning Task Force unanimously approved a suite of recommendations on November 5th to improve Austin Energy's proposed Generation Plan. Five out of the nine members endorsed the Plan with an additional provision to set a target of ending our coal addiction by 2020.

"Business leaders, environmentalists and energy experts on the Task Force agreed that Austin Energy can and should do even more on energy efficiency and on-site distributed solar," noted Cyrus Reed, Conservation Director of the Lone Star Chapter of the Sierra Club. "Some on the Task Force didn't want to take a specific stand on coal-burning, while some thought we should commit to phasing out the coal plant by 2014. In the spirit of consensus, five agreed that we should set a target by 2020, and then during the next two years look at how fast we can do it."

2020 ok for Austin, TX

The Mayor's appointed Task Force met for approximately five months, reviewing more than 15 potential scenarios for managing Austin's energy and crafted a series of recommendations to City Council on how to improve the municipal utility's recommended plan.

The Task Force did not reach a consensus endorsement of Austin Energy's proposal to get 35 percent of its electricity from renewable resources by 2020, while running its portion of the coal-fired Fayette Power Plant less and increasing energy efficiency programs. However, the nine-member task force did reach consensus on other goals, including:
- Raising the energy efficiency goal to reduce total demand by 1,000 megawatts by 2020, an increase of 200 megawatts compared to Austin Energy's Recommended Plan;
- A specific recommendation on energy efficiency programs for low-income Austinites to continue to fund weatherization programs for those at 200 percent or less of the poverty level;
- Creating a separate 200 megawatt goal for sustainable on-site distributed renewable energy resources like solar and geothermal through rebates, loans, and other incentives;
- Creating a much more transparent and public process for future decision-making on energy, including much more information-sharing on rates, fuel charges and

reliability indicators;
• Reviewing the Generation Plan in a public process every two years to see if it should be revised;
• Creating a specific carbon dioxide cap aligned with the generation plan that commits Austin Energy to go beyond any federal mandates and make reductions in carbon dioxide from all resources when adding any new carbon resources like natural gas plants.

Five out of the nine members of the Task Force endorsed the Austin Energy Generation Plan with the recommendation that Austin Energy commit to a target to further ramp down or phase out its reliance on burning coal for electricity by 2020, with a re-assessment within two years showing if it is economically and technologically feasible. Public Citizen and Sierra Club developed the successful resolution to phase out coal.

"Public Citizen and Sierra Club agree that we can and must get out of the coal plant by 2020, and with this recommendation to City Council, the Austin Generation Resource Planning Task Force has set up a process to do that," noted Public Citizen's Matthew Johnson, who also served on the Task Force.

###

Explore, enjoy and protect the planet.

Lone Star Chapter, Sierra Club

Masthead
Published Wed, May 05, 2010 05:08 AM
Modified Wed, May 05, 2010 07:08 AM

UNC vows to end coal use by 2020

CHAPEL HILL UNC-Chapel Hill has pledged to phase out coal use by 2020.

The decision, announced Tuesday, echoes a key recommendation of a campus energy task force and the pleas of a very active student group that has urged UNC-CH for months to stop burning coal at its power plant.

The change would move UNC-CH closer to its goal of becoming carbon neutral by 2050.

But there are potential obstacles.

The move hinges on the ability of the cogeneration plant's boilers to burn the new, cleaner fuel. It will be biomass, first dried wood pellets and eventually torrefied wood, a product similar to charcoal. The university will soon begin testing the boilers.

If the cogeneration plant was at the end of its lifespan, it could simply be scrapped in favor of a new technology, said UNC-CH Chancellor Holden Thorp. But it has 30 to 40 years left, a long enough life span that it makes sense to continue using it.

"We have perfectly good boilers," Thorp said. "Our challenge is how to make a new fuel work in it."

Assuming that it works, the use of the cleaner fuel will be possible only if there is enough of it available eventually and it's affordable.

Moving away from coal can be costly.

At Duke, coal-fired boilers heated campus buildings for 50 years until a plant on that campus closed in 1978. It reopened last year after a $25 million renovation and now burns gas, which is cleaner.

At UNC-CH, ending coal use by 2020 was one of six recommendations made by a task force that is still studying campus energy issues.

The cogeneration plant on West Cameron Avenue burns coal and natural gas to produce one-third of the university's power, and it accounts for at least 60 percent of UNC-CH's greenhouse gas emissions each year.

The Sierra Club is in the midst of a national "Beyond Coal" campaign, and on the UNC-CH campus, students working with that project have spent much of the year lobbying for the move away from coal.

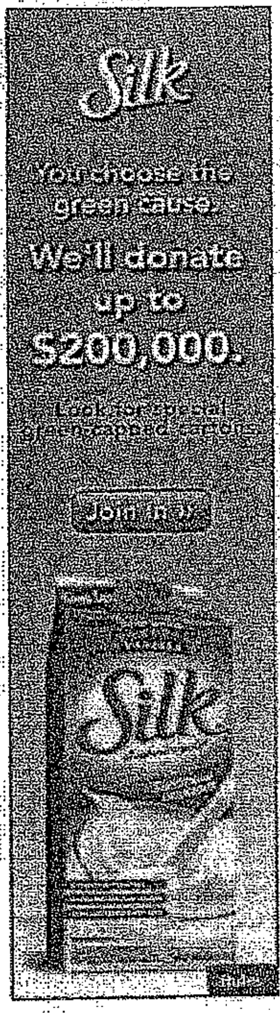
That Sierra Club campaign is on about 40 campuses, and UNC-CH is the first to commit to ending coal use.

"It's a remarkable step," said Bruce Nilles, the campaign's national director.

"For the university to say it's going to do its part is a huge step forward," Nilles said.

2020 is a "remarkable step" for NC

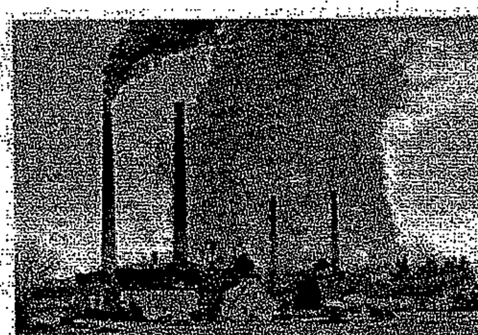
eric.ferreri@newsobserver.com or 919-932-2008



Sierra Club opinion saying 2020 OK for Pac NW

The first three days of this week are seeing a slew of activities taking on coal. We have events in 25 states to counter the coal industry and cheer on clean energy investments.

It's all part of our National Day of Action, and there are events happening across the nation, including rallies, public hearings, coal deliveries to polluters, press conferences, brown bag lunches, coal tours, and town hall meetings.



Our Campuses Beyond Coal campaign is holding photo petition events on a dozen campuses nationwide, calling on campus administrators to shut down old, dirty coal plants polluting those universities and the neighboring towns.

These events are all sending one message from coast to coast – coal is dirty business, and we need clean energy. You should check the website to learn more about these creative events and see if there are any taking place near you.

As we watch activists in these states work together for clean energy, we want to highlight a few states taking steps in the right direction that we hope other states will emulate. The Governors of Washington (Chris Gregoire), Oregon (Ted Kulongoski) and Montana (Brian Schweitzer) have all committed their states to meeting climate goals and investing in a clean energy future.

Now these three governors can continue to lead the way and take another tangible action within the region that will make significant progress towards meeting those goals. Directing the Northwest Power and Planning Conservation Council's (NWPCC - the region's official power planning agency) latest power plan to phase out coal by 2020, assign a responsible cost to carbon pollution, and maintain high energy efficiency goals.

This may be the one action they can take that is solely under their power to deliver. And they can do it today. This would get the region on a path to reducing the emissions from our electricity by 77% and ensure a safer, cleaner, more reliable energy portfolio overall.

NWPCC has even stated that "serious efforts to reduce or even stabilize CO_2 production beyond 2005 will likely require replacing existing coal-fired power plants with low CO_2-emitting resources."

Washington's Gregoire and Oregon's Kulongoski have made real progress and paved the way for meeting the climate challenge. The 6th Power Plan is an excellent opportunity for Montana Governor Brian Schweitzer to demonstrate a true commitment to meeting the scientific goals for climate change.

This step with the NWPCC would mesh well with the states' actions thus far:

- All three states signed onto strong carbon pollution reductions through the Western Climate Initiative, committing to at least a 15 percent reduction in carbon pollution from 2005 levels by 2020.

- They are a part of the Western Governor's Association climate resolution that urges a national policy to reduce greenhouse gas emissions.

But this action with the NWPCC is something they can do in the Northwest to show the rest of the world that there is a better way. We urge the governors to stay true to their vision now with the NWPCC Power Plan – they should improve the current plan by maintaining maximum energy efficiency goals, putting a price on carbon emissions, and stating, as a goal, the plan to move the region off coal power by 2020.

This would be the single most important step they can take to have any real chance of meeting their states goals and making real their personal commitment to this important issue.

http://www.coolstatewashington.org/calendar_display.php?id=1886

If you're in the Seattle area, you can help promote this idea of moving the region off coal at a rally on Wednesday night. Otherwise, be sure to find any National Day of Action events near you.

The NWPCC is also having hearings throughout the northwest where you can make your voice heard for a Coal-Free northwest:

- Seattle, Wednesday, Sept 30. (http://www.coolstatewashington.org/calendar_display.php?id=1886)
- Missoula, Tuesday, October 13. (Contact Brad Hash for information: brad.hash@sierraclub.org)
- Portland, Wednesday, October 14. (http://oregon.sierraclub.org/)

Though it has spent millions on 'clean' coal advertising, the truth is that the coal industry has for years actively fought against cleaning up the existing fleet of over 500 coal-fired power plants, some of them dating back to the Eisenhower Administration.

The industry must stop trying to block common sense regulations and policies that will protect communities and the environment. Rather than seeing these efforts as a threat to jobs and the economy, such regulations are the path forward to protect people's livelihoods.

Strong regulations put us on a path to cleaner technology that boosts economic growth, creates jobs and protects the planet.

We didn't use to have a choice about how to power America. Today we can do better. It's time to clean up pollution from coal and build the clean energy economy.

Note: *This is a guest post from Nathan Good of the Sierra Club. It was co-written by Kathleen Ridihalgh, Senior Representative for the Sierra Club's Northwest Region.*

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thank's for you article...very nice

Written in February

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traveller gasoline

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Virginia Tech Beyond Coal

Join with us as we work to bring a clean energy future to Virginia Tech by investing in renewable energy research and closing the Virginia Tech campus dirty coal plant.

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- VT Beyond Coal in the Media
- VT Beyond Coal Supporters

Posted by: Andy Rush | April 2, 2010

Beyond Coal Unveils Energy Proposal For Administration

Supporters of Virginia Tech's Beyond Coal Campaign assembled on the Drillfield yesterday to present the university administration with the "Hokies' Declaration of Coal Independence."

The declaration, a poster-sized document with almost 2,000 signatures, was carried from the Drillfield to President Charles Steger's office by a large group of supporters after the event.

Members of the Beyond Coal Campaign will meet with Sherwood Wilson, vice president of administrative services, Friday to discuss moving Tech away from coal. However, no administrators were present at the declaration event yesterday.

2020 ok for Virginia

Beyond Coal has pressed to see Tech move away from coal in a transition to cleaner fuels. Its aim is to have a coal-independent campus by 2020.

"Coal is an old fuel source," said sophomore Kara Dodson, project coordinator for Beyond Coal. "We need clean energy sources for our university, for our state and for our nation."

Senior mining engineering major Chris Noble said the goal is unrealistic.

"I support the ideals of being more environmentally friendly and to drop carbon emissions, but I don't necessarily agree with the timeframe," Noble said. "The idea of renewable energy will not be ready for sure by 2020, not on the scale that we need it."

According to university spokesman Larry Hincker, Tech has not taken a position on the coal issue.

"The university will take a look at what the students are proposing, but the university does not have a stand on the issue," Hincker said. "The key thing is for us and the students to understand the implications of what is being proposed."

Among the speakers at the event was town councilman Don Langrehr.

"By continuing the reliance on coal we're falling behind, and it causes two kinds of problems: financial and environmental," Langrehr said.

He said as an older industry, coal is not providing as many new jobs as renewable energy sources could. He added burning coal has caused an increased rate of asthma and other respiratory problems.

Also attending the event was Jaclyn Catlett, a sophomore who lived in Thomas Hall last year. Thomas is located on the upper quad next to the power plant.

While living in Thomas, Catlett suffered severe health problems including tonsillitis and pharyngitis, and she was told by doctors at Schiffert Health Center that the problems were caused by exposure to coal dust from the plant.

"I lived there my first semester and got sick six or seven times. I got to the point where they put me on antibiotics for the whole semester," Catlett said. "I missed most of my classes, because I was up all night because I couldn't breathe."

Catlett moved to Main Eggleston Hall during the second semester of her freshman year and has not had respiratory problems since.

She sent emails to the administration about her issue, but was told that there was not enough funding to provide filters or other equipment necessary to make the coal cleaner.

"I was really frustrated, I just felt like I kept getting shot down," Catlett said.

Jackie Pontious, a former president of the Environmental Coalition who graduated in 2009, also spoke.

"We as students are having to educate our educators," Pontious said. "Our motto is 'Invent the Future.'

As students, we like to say 'Invent the Right Future.'"

Article written by Claire Sanderson from the Collegiate Times. It can be found originally here.

Posted in Events, Media

« Invent the Right Energy Future

Categories

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Twitter Updates

- Check out our big list of supporters! http://vtbeyondcoal.wordpress.com/vt-beyond-coal-supporters/ 3 weeks ago
- Coal's Toxic Sludge: http://www.rollingstone.com/politics/story/32742962/coals_toxic_sludge 1 month ago
- An article from the CT: http://www.collegiatetimes.com/stories/15227/tech-should-lead-the-pack-

COLUMNS

Gophers still dig coal despite being so green

The University should end its use of dirty energy sources.

PUBLISHED: 02/14/2010
BY JENNIFER BISSELL

It's a sunny, fall day and you're touring the University of Minnesota. You're thinking about applying there next year.

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You stop at the intersection on the edge of campus by Annie's Parlor and look out to the view of the city skyline. Then something catches your eye that doesn't catch the attention of most students. It's a steam plant along the Mississippi with smoke billowing out of its stacks.

Your tour guide explains, "And that is the University's Southeast Steam Plant. It's located near the Stone Arch Bridge, pollutes the river with mercury and emits thousands of tons of CO_2 into the air surrounding campus."

Now, I admit this is a sensationalized story meant to raise alarm while I only present a fraction of the facts. You should also know that the University is committed to energy efficiency and is a leader in the field. In fact, the University should be proud of the strides it has made in sustainability.

The University is a member of the Chicago Climate Exchange, has supported more than 400 research projects on renewable energy and the environment, has adopted a green construction policy for all new buildings, regularly promotes waste prevention in its dining and residential halls, is committed to energy efficiency and, in truth, has greatly reduced its dependence on carbon-based energy sources.

But now it's time for the next step: becoming coal-free.

Currently, the University's East Bank steam plant primarily uses clean energy sources such as natural gas, biomass and, innovatively, oat hulls. However, according to University Services spokesman Tim Busse, 23 percent of its energy still comes from coal.

According to the U.S. Energy Protection Agency, burning coal is the dirtiest way to produce electricity and is a leading source of global warming pollution. Additionally, the Sierra Club estimates that each year 21,000 hospitalizations, 38,000 heart attacks and 24,000 deaths are caused by coal plant pollution nationwide.

These numbers are startling, but they're only a couple from the hundreds of statistics to choose from.

Beyond Coal, a University student organization in conjunction with the Sierra Club, estimates that in 2009 the University burned 38,740 tons of coal. To some calculations, this would equate to 77,480 tons of carbon dioxide pollutants in the air around campus.

Siri Simons, president of Beyond Coal, stresses the importance of being coal-free for three reasons: the environment, public health concerns and the University's image as a sustainability leader.

Speaking on her experience as an environmental studies major, Simons pointed to the irony of learning about renewable energy from an institution that still relies on fossil fuels.

"Why is what we are being taught in the classroom not put into practice on campus?" Simons said. "We are a huge research institution. Put students, put environmental students, put grad students on these projects and help them put what they're learning in the classroom onto campus."

There is no disputing that this could be a slow and costly plan. With the University's state funding slashed, it could even be considered unreasonable to demand this. However, Beyond Coal and its supporters understand this. The group is not demanding the University go coal-free now but that it make a feasible plan to do so in the future.

As Simons pointed out, the University has a lot of resources to help facilitate this process. The University could easily ask the students for their help, ask alumni for donations and apply for clean-energy grants. Just as the University funded TCF Bank Stadium through a collapsing economy, it could also fund a coal-free energy plant if it were made a priority.

Universities across the nation are ending their dependence on coal completely. Even rival institution University of Wisconsin made the change. Their heating plant, by far the largest coal plant in Wisconsin, is scheduled to be converted into a biomass energy plant by 2012.

Burning more than 100,000 tons of coal a year, the plant is more than twice the size of the University of Minnesota's plant, which begs the question: If they can do it, why can't we?

Jessica Tatro, a regional representative of the Sierra Club Beyond Coal Campaign, said their organization is currently encouraging the University of Minnesota to conduct a feasibility study into ways in which the University could become coal-free by 2015. She said ultimately how the coal-free effort is made is in the hands of the University and that even Beyond Coal's timeline could be extended to 2020 if needed. But first the University would need to look into how this could become possible and how to finance it.

"What is really important is the University is making that public commitment," Tatro said. "It's about being a leader in sustainability and taking that step and moving forward. Coal is the energy of the past; renewable is the energy of the future. We need to be moving toward the future."

While the transition to cleaner energy sources can require a large financial commitment, renewable energy sources such as wind power and solar panels eventually pay for their own installation costs. These savings could be used for new investments in technology, student aid and staff.

"This University needs to continue to recruit students, needs to continue to be that leader — to get more people, to get more faculty, to get more dollars into the institution," Tatro said. "Taking that step is going to help draw those people and dollars into the University."

Jennifer Bissell welcomes comments at jbissell@mndaily.com.

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2020 ok for Minnesota

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LC 48

PGE's 2009 Integrated Resource Plan

Attachment 3

Portfolio Performance Scoring Grid

	Scoring Consideration	Within Efficient Frontier Zone?	Meets Operating Reserve Req?	Cost: Expected Cost Reference Case	Prob. of Poor Perf.	Prob. of Good Perf.	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variation	Reliability: TailVar Unserved Energy 2012-2020	Diversity: Technology HHI	Diversity: Fuel HHI
	Units	Y or N	Y or N	$ NPV	%	%	%	$ NPV Million	$ NPV Million	$ NPV Million	$ NPV Million	Trillion	MWa	Points	Points
1	Market	Y	N	$ 27,211	5%	90%	86%	$ 36,155	$ 8,943	$ 35,414	$ 8,631	70	1050	2154	2316
2	Natural Gas	Y	Y	$ 29,027	10%	5%	-5%	$ 35,436	$ 6,410	$ 36,675	$ 8,458	53	755	2917	2113
3	Wind	Y	Y	$ 29,288	5%	14%	10%	$ 34,238	$ 4,949	$ 35,037	$ 6,547	78	779	3137	2055
4	Diversified Green	Y	Y	$ 28,987	0%	14%	14%	$ 34,091	$ 5,104	$ 34,718	$ 6,624	61	777	2656	1958
5	Diversified Thermal with Wind	Y	Y	$ 28,891	5%	0%	-5%	$ 34,949	$ 6,057	$ 36,175	$ 8,025	57	763	2660	2079
6	Bridge to IGCC in WY	N	Y	$ 32,735	100%	0%	-100%	$ 38,635	$ 5,900	$ 36,950	$ 6,397	47	824	2367	2211
7	Bridge to Nuclear	Y	Y	$ 29,853	81%	0%	-81%	$ 34,863	$ 5,010	$ 34,768	$ 6,311	39	788	2036	1985
8	Green w/ On-peak Energy Target	Y	Y	$ 28,971	0%	19%	19%	$ 33,993	$ 5,023	$ 34,481	$ 6,517	58	754	2656	1907
9	Diversified Thermal with Green	Y	Y	$ 28,674	5%	14%	10%	$ 34,910	$ 6,236	$ 36,116	$ 8,171	53	760	2532	2073
10	Boardman through 2014	Y	Y	$ 28,593	10%	10%	0%	$ 35,126	$ 6,533	$ 38,112	$ 9,689	63	742	3075	2172
11	Oregon CO2 Goal	N	Y	$ 30,375	81%	14%	-67%	$ 35,007	$ 4,632	$ 36,112	$ 6,665	63	764	2702	1824
12	PGE 2020 BART II	Y	Y	$ 28,396	0%	81%	81%	$ 34,770	$ 6,374	$ 36,999	$ 8,987	61	751	3075	2079
13	Diversified Green with wind in WY	Y	Y	$ 30,828	86%	0%	-86%	$ 35,962	$ 5,134	$ 35,399	$ 6,191	37	772	2576	1966
14	Diversified Thermal w/ Green w/o lease	Y	Y	$ 28,668	0%	10%	10%	$ 34,891	$ 6,223	$ 36,461	$ 8,432	54	748	2615	2088
15	DEQ 2020 (Option 1)	N	Y	$ 28,758	5%	0%	-5%	$ 35,145	$ 6,387	$ 37,314	$ 8,985	61	750	3075	2101
16	DEQ 2018 (Option 2)	Y	Y	$ 28,521	0%	48%	48%	$ 34,967	$ 6,445	$ 37,373	$ 9,196	62	740	3075	2106
17	DEQ 2015 (Option 3)	Y	Y	$ 28,546	10%	19%	10%	$ 35,045	$ 6,499	$ 37,815	$ 9,489	63	729	3075	2135
18	PGE 2020 BART III	Y	Y	$ 28,499	0%	62%	62%	$ 34,876	$ 6,377	$ 37,056	$ 8,986	61	749	3075	2102

Performance Range for Scoring Normalization:

Best Performing Portfolio(s)			$ 27,211			86%	$ 33,993	$ 4,632	$ 34,481	$ 6,191	37	729.3	2,036	1,824
Best Basis			Min			Max	Min	Min	Min	Min	Min	Min	Min	Min
Worst Performing Portfolio(s)			$ 32,735			-100%	$ 38,635	$ 8,943	$ 38,112	$ 9,689	78	1,050.0	3,137	2,316
Spread Best to Worst			$ 5,524			186%	$ 4,641	$ 4,311	$ 3,631	$ 3,498	42	320.6	1,101	492
% Difference			20.3%				13.7%	93.1%	10.5%	56.5%	113.9%	44.0%	54.1%	27.0%

	2. Portfolio Evaluation Scoring: Normalized Scores (0 to 100)	Screening		Deterministic				Stochastic			Reliability & Diversity		
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Frontier Zone?	Meets Operating Reserve Req?	Cost: Expected Cost	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variation	Reliability: Avg. EUE 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI
1	Market	Y	N	100.0	100.0	53.4	0.0	74.3	30.2	19.3	0.0	89.3	0.0
2	Natural Gas	Y	Y	67.1	51.3	68.9	58.8	39.6	35.2	60.8	91.9	20.0	41.3
3	Wind	Y	Y	62.4	59.0	94.7	92.6	84.7	89.8	0.0	84.6	0.0	53.1
4	Diversified Green	Y	Y	67.9	61.5	97.9	89.1	93.5	87.6	40.6	85.2	43.7	72.6
5	Diversified Thermal with Wind	Y	Y	69.6	51.3	79.4	66.9	53.3	47.6	52.3	89.4	43.3	48.2
6	Bridge to IGCC in WY	N	Y	0.0	0.0	0.0	70.6	32.0	94.1	74.7	70.5	69.9	21.3
7	Bridge to Nuclear	Y	Y	52.2	10.3	81.3	91.2	92.1	96.6	93.5	81.6	100.0	67.2
8	Green w/ On-peak Energy Target	Y	Y	68.1	64.1	100.0	90.9	100.0	90.7	47.9	92.4	43.7	83.2
9	Diversified Thermal with Green	Y	Y	73.5	59.0	80.3	62.8	55.0	43.4	61.2	90.5	54.9	49.3
10	Boardman through 2014	Y	Y	75.0	53.8	75.6	55.9	0.0	0.0	37.6	96.1	5.6	29.3
11	Oregon CO2 Goal	N	Y	42.7	17.9	78.2	100.0	55.1	86.5	37.4	89.2	39.5	100.0
12	PGE 2020 BART II	Y	Y	78.6	97.4	83.3	59.6	30.6	20.1	42.9	93.3	5.6	48.0
13	Diversified Green with wind in WY	Y	Y	34.5	7.7	57.6	88.4	74.7	100.0	100.0	86.8	50.9	71.1
14	Diversified Thermal w/ Green w/o lease	Y	Y	73.6	59.0	80.7	63.1	45.5	35.9	58.3	94.1	47.4	46.3
15	DEQ 2020 (Option 1)	N	Y	72.0	51.3	75.2	59.3	22.0	20.1	41.0	93.6	5.6	43.6
16	DEQ 2018 (Option 2)	Y	Y	76.3	79.5	79.0	57.9	20.3	14.1	39.3	96.6	5.6	42.7
17	DEQ 2015 (Option 3)	Y	Y	75.8	59.0	77.4	56.7	8.2	5.7	38.0	100.0	5.6	36.8
18	PGE 2020 BART III	Y	Y	76.7	87.2	81.0	59.5	29.1	20.1	41.2	93.9	5.6	43.4

	3. Portfolio Evaluation Scoring: Total Weighted Scores	Screening		Deterministic				Stochastic			Reliability & Diversity					
		(a)	(b)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(l)	(m)	(n)
	Scoring Consideration	Within Efficient Frontier Zone?	Meets Operating Reserve Req?	Cost: Expected Cost	Risk Durability: Good minus Bad	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk Magnitude: Avg. Worst 4 vs. Reference Case	Risk: TailVar	Risk: TailVar less Mean	Risk: Year-to-Year Variation	Reliability: Avg. EUE 2012-2020 & 2025	Diversity: Technology HHI	Diversity: Fuel HHI	Weigted Combined Score (0 to 100)	Performance vs. Best (%)	Ordinal Ranking
	Weight			50%	10%	5%	5%	3.3%	3.3%	3.3%	15%	2.5%	2.5%			
1	Market	Y	N	50.0	10.0	2.7	0.0	2.5	1.0	0.6	0.0	2.2	0.0	69.0	92%	8
2	Natural Gas	Y	Y	33.6	5.1	3.4	2.9	1.3	1.2	2.0	13.8	0.5	1.0	64.9	87%	14
3	Wind	Y	Y	31.2	5.9	4.7	4.6	2.8	3.0	0.0	12.7	0.0	1.3	66.3	88%	11
4	Diversified Green	Y	Y	33.9	6.2	4.9	4.5	3.1	2.9	1.4	12.8	1.1	1.8	72.5	97%	3
5	Diversified Thermal with Wind	Y	Y	34.8	5.1	4.0	3.3	1.8	1.6	1.7	13.4	1.1	1.2	68.0	91%	10
6	Bridge to IGCC in WY	N	Y	0.0	0.0	0.0	3.5	1.1	3.1	2.5	10.6	1.7	0.5	23.1	31%	18
7	Bridge to Nuclear	Y	Y	26.1	1.0	4.1	4.6	3.1	3.2	3.1	12.2	2.5	1.7	61.6	82%	15
8	Green w/ On-peak Energy Target	Y	Y	34.1	6.4	5.0	4.5	3.3	3.0	1.6	13.9	1.1	2.1	75.0	100%	1
9	Diversified Thermal with Green	Y	Y	36.8	5.9	4.0	3.1	1.8	1.4	2.0	13.6	1.4	1.2	71.3	95%	5
10	Boardman through 2014	Y	Y	37.5	5.4	3.8	2.8	0.0	0.0	1.3	14.4	0.1	0.7	66.0	88%	12
11	Oregon CO2 Goal	N	Y	21.4	1.8	3.9	5.0	1.8	2.9	1.2	13.4	1.0	2.5	54.9	73%	16
12	PGE 2020 BART II	Y	Y	39.3	9.7	4.2	3.0	1.0	0.7	1.4	14.0	0.1	1.2	74.6	99%	2
13	Diversified Green with wind in WY	Y	Y	17.3	0.8	2.9	4.4	2.5	3.3	3.3	13.0	1.3	1.8	50.6	67%	17
14	Diversified Thermal w/ Green w/o lease	Y	Y	36.8	5.9	4.0	3.2	1.5	1.2	1.9	14.1	1.2	1.2	71.0	95%	7
15	DEQ 2020 (Option 1)	N	Y	36.0	5.1	3.8	3.0	0.7	0.7	1.4	14.0	0.1	1.1	65.9	88%	13
16	DEQ 2018 (Option 2)	Y	Y	38.1	7.9	4.0	2.9	0.7	0.5	1.3	14.5	0.1	1.1	71.1	95%	6
17	DEQ 2015 (Option 3)	Y	Y	37.9	5.9	3.9	2.8	0.3	0.2	1.3	15.0	0.1	0.9	68.3	91%	9
18	PGE 2020 BART III	Y	Y	38.3	8.7	4.0	3.0	1.0	0.7	1.4	14.1	0.1	1.1	72.4	97%	4

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PGE's 2009 Integrated Resource Plan

Attachment 4

PGE's Response to OPUC Data Request 001 (a) and (b)

February 8, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC-48
PGE *First Supplemental* Response to OPUC Data Request
Dated December 8, 2009
Question No. 001

Request:

Please provide detailed portfolio analysis of the following alternative Boardman replacement strategies:

a. **Modify "Porfolio 10 – Boardman through 2014" by replacing the 441 MW CCCT in 2015 with the combination of a 221 MW share of a CCCT in 2015 and the remainder with wholesale market purchases.**

b. **Modify "Portfolio 10 - Boardman through 2014" by replacing the 441 MW CCCT in 2015 with the combination of a 221 MW share of a CCCT in 2015 and the remainder with additional wind resource in 2015.**

c. **Modify "Portfolio 10 - Boardman through 2014" by shifting the Boardman replacement date from 2014 to 2020.**

Response (dated January 19, 2010):

a. (to be provided at a later date)

b. (to be provided at a later date)

c. Attachment 001-A provides the analytical results for the requested new portfolio, which has been labeled as "Boardman through 2020".

For this request, we have assumed installation of low-nox burners, over-fire air ports, and mercury controls in 2011 and continued operations through December, 2020. (The "Boardman through 2014" portfolio has these same investments.) We further assume that all investment in the plant is recovered by 2020. After 2020, we assume replacement of the plant by a generic CCCT of the same size and cost characteristics (in real $) as for replacement in 2015 in the "Boardman through 2014" portfolio. All other inputs and assumptions remain unchanged.

First Supplemental Response (dated February 8, 2010):

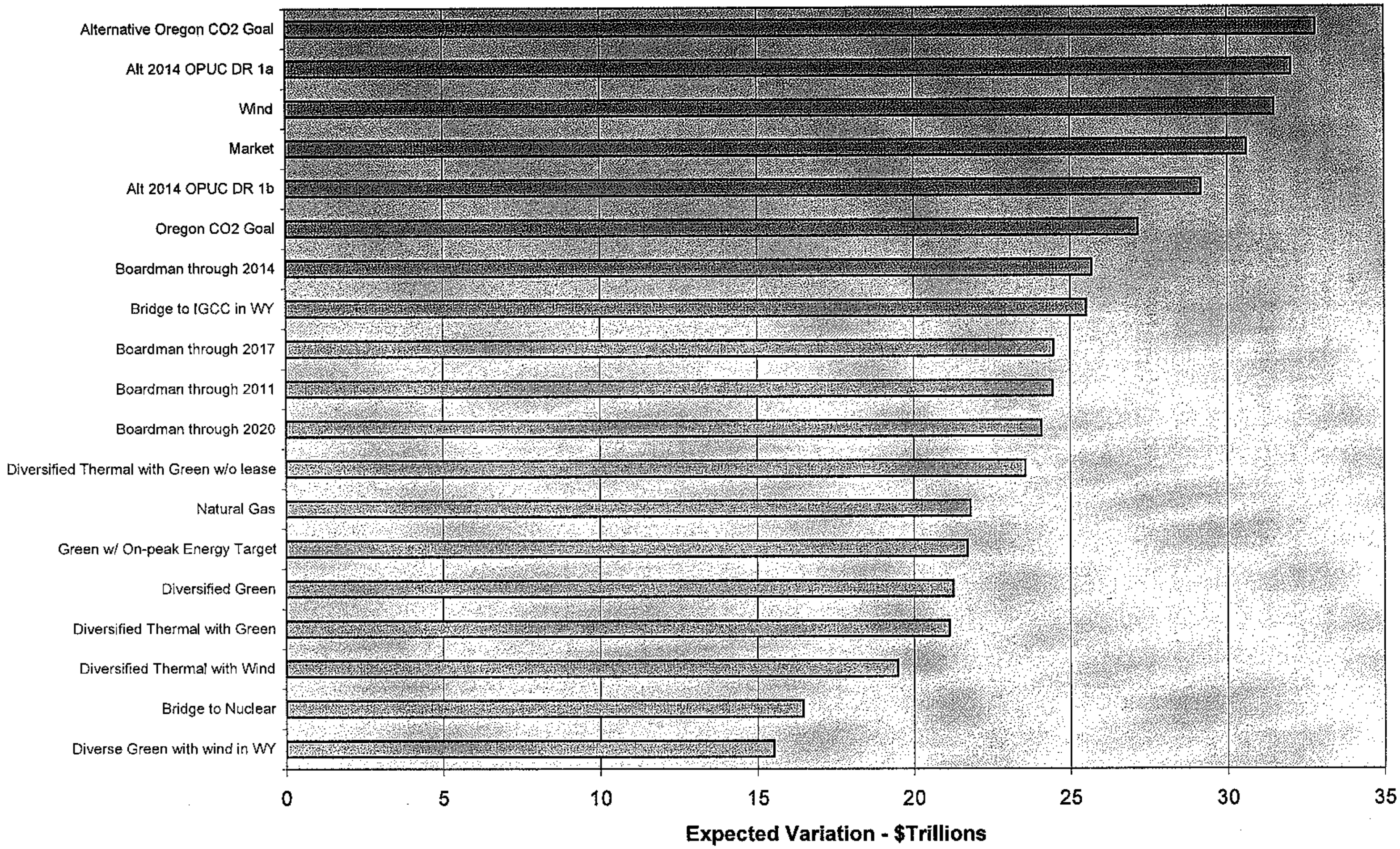
a. Attachment 001-B provides analytical results for the requested new portfolio, which has been labeled "Alt 2014 OPUC DR 1a".

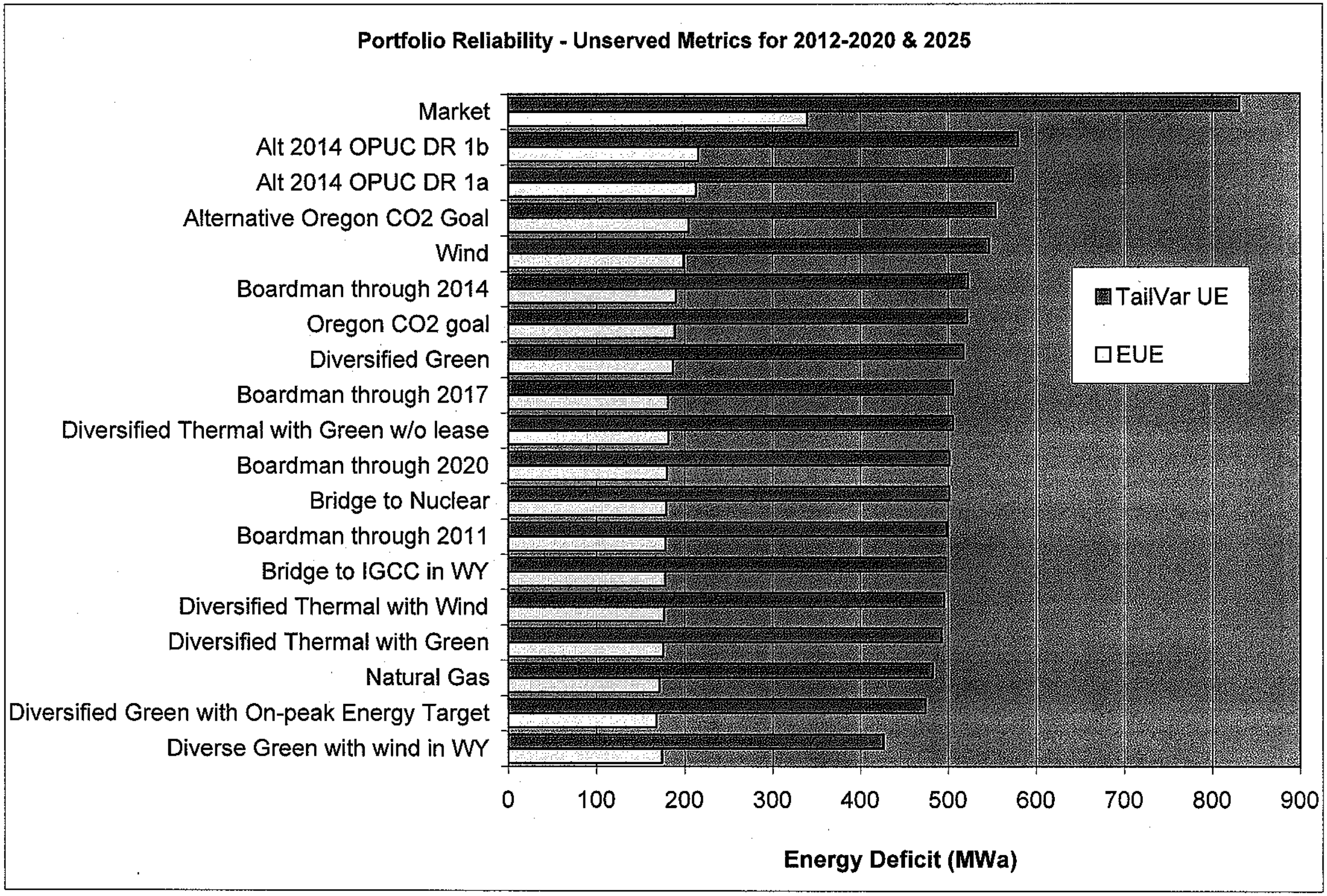
b. Attachment 001-B provides analytical results for the requested new portfolio, which has been labeled as "Alt 2014 OPUC DR 1b". In addition to 221 MW of a CCCT, this portfolio adds 371 MW of PNW wind resources in 2015.

LC-48
Attachment 001-B

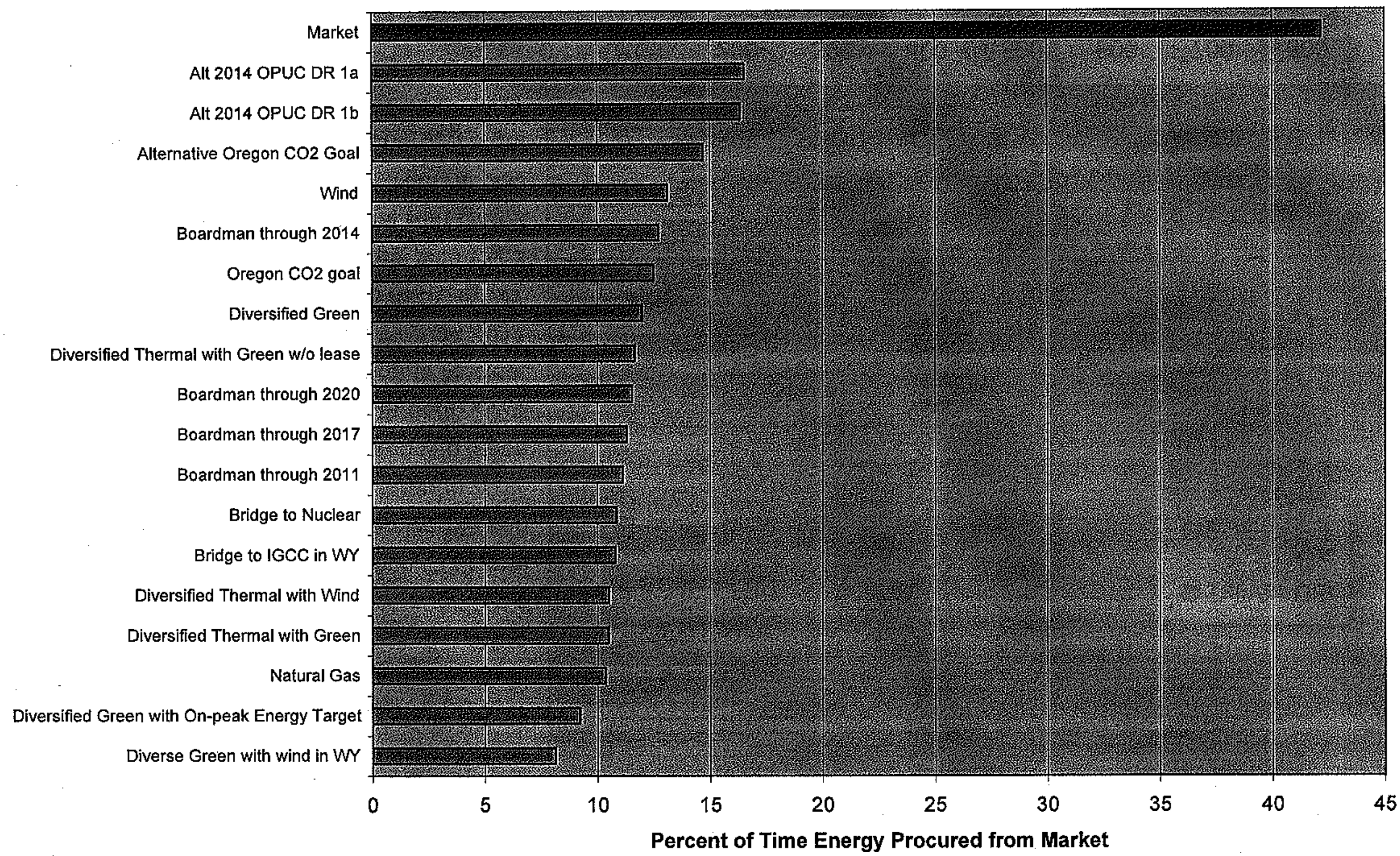
Analytical Results

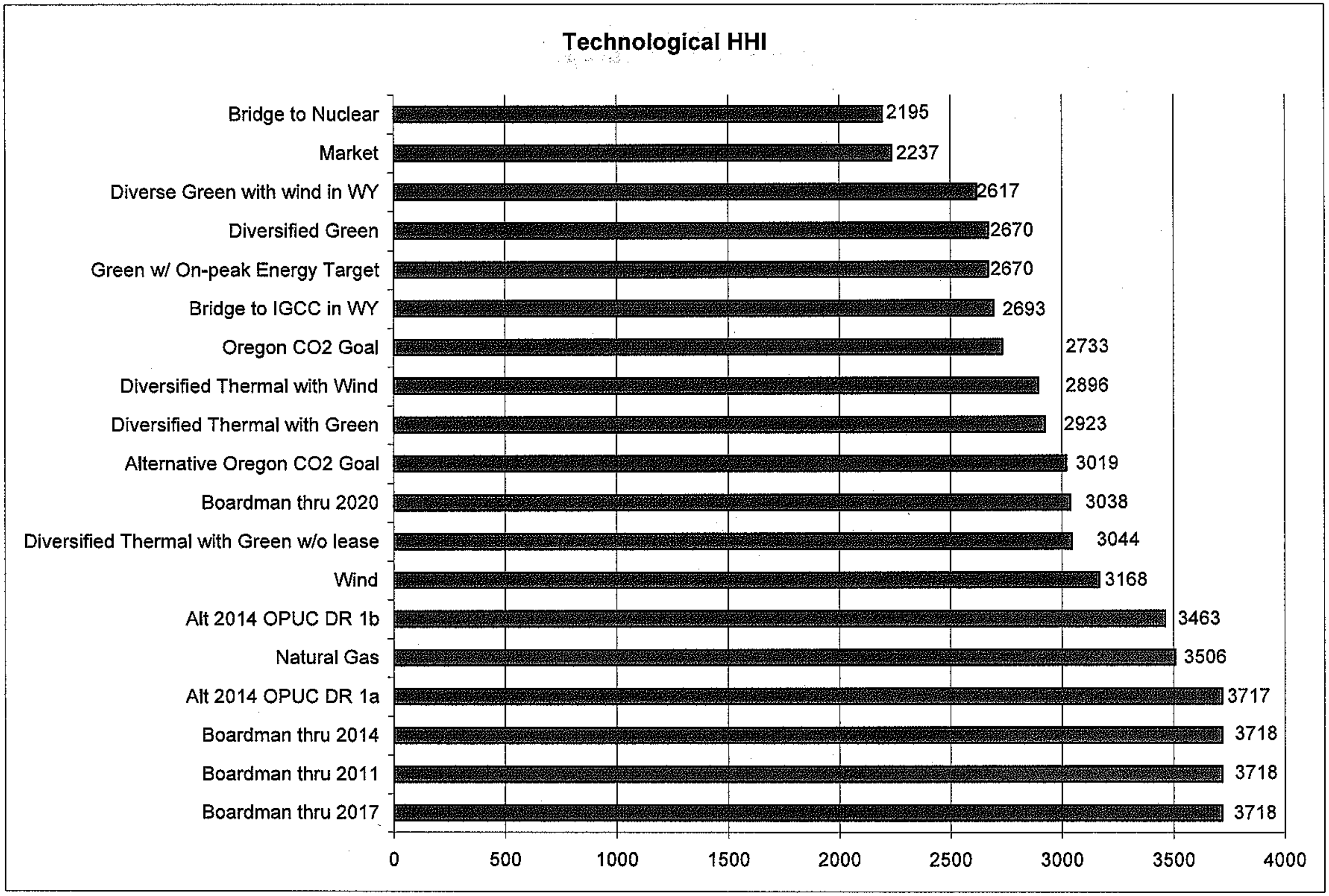
Year-to-Year Portfolio Average Variation

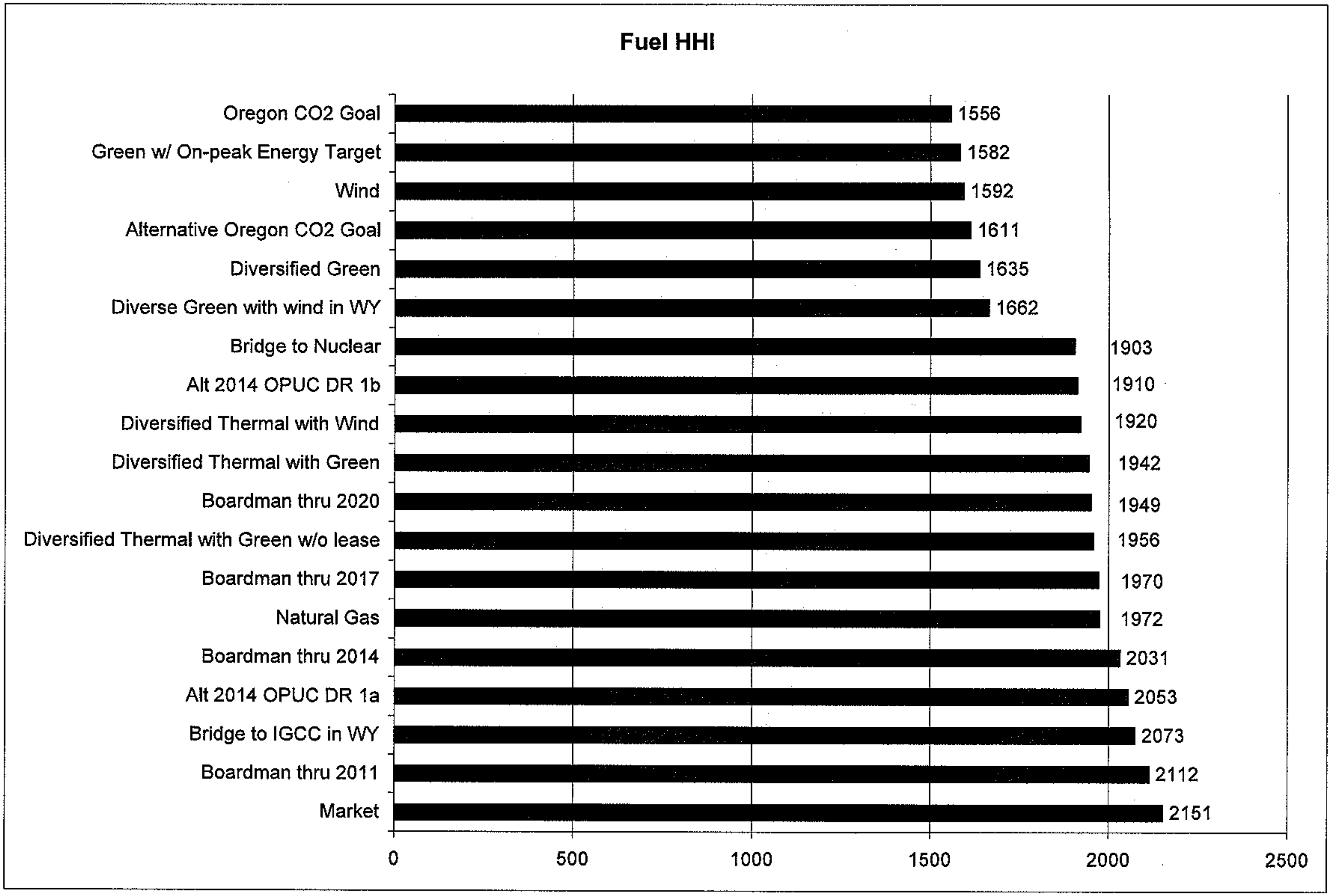



Portfolio Reliability - Unserved Metrics for 2012-2020 & 2025
Market
Alt 2014 OPUC DR 1b
Alt 2014 OPUC DR 1a
Alternative Oregon CO2 Goal
Wind
Boardman through 2014
Oregon CO2 goal
Diversified Green
Boardman through 2017
Diversified Thermal with Green w/o lease
Boardman through 2020
Bridge to Nuclear
Boardman through 2011
Bridge to IGCC in WY
Diversified Thermal with Wind
Diversified Thermal with Green
Natural Gas
Diversified Green with On-peak Energy Target
Diverse Green with wind in WY
TailVar UE
EUE
0
100
200
300
400
500
600
700
800
900
Energy Deficit (MWa)

Portfolio Reliability - LOLP




Technological HHI
Bridge to Nuclear
Market
Diverse Green with wind in WY
Diversified Green
Green w/ On-peak Energy Target
Bridge to IGCC in WY
Oregon CO2 Goal
Diversified Thermal with Wind
Diversified Thermal with Green
Alternative Oregon CO2 Goal
Boardman thru 2020
Diversified Thermal with Green w/o lease
Wind
Alt 2014 OPUC DR 1b
Natural Gas
Alt 2014 OPUC DR 1a
Boardman thru 2014
Boardman thru 2011
Boardman thru 2017
2195
2237
2617
2670
2670
2693
2733
2896
2923
3019
3038
3044
3168
3463
3506
3717
3718
3718
3718
0
500
1000
1500
2000
2500
3000
3500
4000


Fuel HHI
Oregon CO2 Goal
1556
Green w/ On-peak Energy Target
1582
Wind
1592
Alternative Oregon CO2 Goal
1611
Diversified Green
1635
Diverse Green with wind in WY
1662
Bridge to Nuclear
1903
Alt 2014 OPUC DR 1b
1910
Diversified Thermal with Wind
1920
Diversified Thermal with Green
1942
Boardman thru 2020
1949
Diversified Thermal with Green w/o lease
1956
Boardman thru 2017
1970
Natural Gas
1972
Boardman thru 2014
2031
Alt 2014 OPUC DR 1a
2053
Bridge to IGCC in WY
2073
Boardman thru 2011
2112
Market
2151
0
500
1000
1500
2000
2500

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PGE's 2009 Integrated Resource Plan

Attachment 5

PGE's Response to OPUC Data Request 054

May 05, 2010

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC-48
PGE Response to OPUC Data Request
Dated March 23, 2010
Question No. 054

Request:

Please list each year and its corresponding growth rate for years subsequent to 1980 in which the rate of non-EE adjusted load growth was at least 2.7%.

Response:

The years in which weather-normalized energy delivery to all customers grew at least 2.7% are in boldface. The data are actuals, not adjusted for the sale/transfer of portions of PGE's service area to public utility districts in 1985 and 2001. As actuals, the data are also net of EE.

Year	Weather Adjusted MWh	% Change from Prior Year
1980	12,882,661	
1981	**13,305,912**	**3.3%**
1982	12,856,585	-3.4%
1983	12,764,033	-0.7%
1984	**13,197,012**	**3.4%**
1985	13,030,969	-1.3%
1986	13,357,013	2.5%
1987	**13,793,193**	**3.3%**
1988	**14,304,526**	**3.7%**
1989	**14,951,171**	**4.5%**

1990	**15,485,573**	**3.6%**
1991	15,850,763	2.4%
1992	16,005,446	1.0%
1993	16,427,552	2.6%
1994	**16,866,721**	**2.7%**
1995	**17,319,908**	**2.7%**
1996	17,436,113	0.7%
1997	**18,396,134**	**5.5%**
1998	**18,934,500**	**2.9%**
1999	19,339,291	2.1%
2000	19,805,808	2.4%
2001	19,097,047	-3.6%
2002	18,725,807	-1.9%
2003	18,536,608	-1.0%
2004	18,685,549	0.8%
2005	18,861,849	0.9%
2006	**19,366,521**	**2.7%**
2007	19,545,789	0.9%
2008	19,708,904	0.8%

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PGE's 2009 Integrated Resource Plan

Attachment 6

Sierra Club Response to PGE's Data Request 021

June 5, 2010

TO: Randy Dahlgreen
Rates and Regulatory Affairs
Portland General Electric Company

LC 48 – Sierra Club, et al., Response to PGE Data Request
Dated May 17, 2010
Question No. 021

Request:

21. Provide all forecasts of natural gas prices prepared since June 1, 2009 by or for or relied upon by any of the Intervenors.

Response:

Intervenors state that they will provide a specific response and supporting documents on June 4, 2010.

First Supplemental Response:

See the price forecasts included in Figures 1 through 5 37 of the May 19, 2010 *Schlissel Technical Consulting, Inc., Comments on PGE 2009 Integrated Resource Plan Public Utility of Oregon Docket No. LC 48.*

LC 48

PGE's 2009 Integrated Resource Plan

Attachment 7

EEI Comment on Federal Cap and Trade Legislation To Address Climate Change
August 06, 2010

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2698
202.508.5000
www.eei.org

EDISON ELECTRIC INSTITUTE

EEI[1] Comment on Federal Cap and Trade Legislation To Address Climate Change August 06, 2010

The most significant legislative proposals considered to date by the Congress to reduce emissions of greenhouse gases (GHGs) are market-based approaches known as "cap and trade" programs. Portland General Electric (PGE) has asked us to comment generally on the nature of the requirements that would be imposed by proposed cap-and-trade legislation. Importantly, market-based approaches such as emissions trading provide regulated companies the flexibility to achieve the emission reduction targets in the most cost-effective fashion possible, by either reducing their own emissions and selling excess allowances, or buying the additional allowances that they need from other firms (or from a government at auction). Either way, the same reductions and atmospheric benefits are achieved.

A wide body of economic and historical evidence—including the government's own analysis of H.R. 2454—demonstrates that market-based systems can achieve the same environmental benefits at considerably lower cost than traditional command-and-control regulations, which require regulated firms to take specific actions or install prescribed technologies. Given that the primary concern with GHG emissions is based on global rather than the localized effects of these emissions, cap and trade has the potential to be an ideal approach from both an economic and environmental compliance perspective to reduce atmospheric loadings of GHGs.

For example, H.R. 2454—the Waxman-Markey energy and climate legislation passed by the U.S. House of Representatives on June 26, 2009–establishes an absolute cap on GHG emissions from covered sectors and allows the trading of emissions permits or "allowances" among covered and non-covered entities. Similar legislation has been considered in the U.S. Senate. The cap-and-trade program contained in H.R. 2454 would cover approximately 84 percent of total U.S. GHG emissions by 2016. The program subjects covered entities to an emissions cap that declines steadily between 2012 and 2050, including a 17-percent reduction in covered emissions by 2020 and an 83-percent reduction by 2050, both relative to a 2005 baseline. Compliance is enforced through a requirement for entities subject to the cap to submit a sufficient number of allowances—which are bankable—to cover their emissions. Meeting this requirement can be achieved by reductions in domestic emissions of exempted sources, by the purchase of domestic or international offsets, or by the purchase of emission allowances from other countries with comparable laws limiting emissions.

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[1] Edison Electric Institute (EEI) is the association of shareholder-owned electric companies, international affiliates and industry associates worldwide. Our U.S. members serve 95 percent of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70 percent of the U.S. electric power industry.

The importance of allowing the use of off-system resources—such as offsets or international allowances—is underscored by the U.S. Environmental Protection Agency's analysis of H.R. 2454, which concluded that relying almost exclusively on efforts by covered sectors alone would lead to allowance prices 148-229 percent[2] greater than under the bill as passed.

It is important to note that the cap-and-trade bills introduced to date (i.e., H.R. 2454, etc.) do not establish emission caps on individual companies or the sources they own/operate, and instead focus on covered sectors. Similarly, the bills focus on allowance allocations at the sector level, and while limits on allocations to a covered sector would impact how many allowances a source or company would be initially allocated, what happens after the initial allocation is determined by the affected companies participating in the market program.

One of the central features of a cap-and-trade system is that the buying and selling of allowances results in a price on emissions, which in turn provides information to companies about whether it is more cost-effective for them to reduce their own GHG emissions or to buy allowances on the market. Ensuring that regulatory agencies, industry, and consumers see this price signal and factor it into their decision making is essential to create the incentive to reduce emissions and to invest in low-carbon technologies. As both the cap and the number of available allowances are reduced over time, all else being equal, the price of GHGs will rise and create a continuing incentive for firms to find new ways to reduce their emissions. This incentive to innovate and induce technological change also lowers emissions-control costs over time.

Under H.R. 2454 and similar cap-and-trade approaches, the market price of allowances will establish an incremental cost to emitting GHGs. That cost provides an incentive to reduce emissions since operating costs can be reduced by emitting less and any unused allowances can be sold. Whether a firm decides to reduce its own emissions, purchase allowances from others, or some combination of the two, will depend on its specific circumstances. Regardless, the price of allowances provides a fundamental and vital price signal that allows each firm to evaluate its resource allocation options and decisions. Until a price on carbon becomes a reality, it is entirely reasonable for companies to use allowance price predictions or modeled prices for resource planning purposes.

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[2] U.S. Environmental Protection Agency, "Supplemental EPA Analysis of the American Clean Energy and Security Act of 2009," 19 (scenarios 9 & 11) (Jan. 29, 2010)