State of Oregon

Department of Environmental Quality — Memorandum

Date: May 26, 2010

To: Environmental Quality Commission

From: Dick Pedersen, Director

Subject: Agenda item I, Action item: DEQ recommendation for EQC action on PGE petition
June 16-17, 2010 EQC meeting

Why this is important

On April 2, 2010, PGE submitted a petition to the commission to revise air pollution control rules for the Boardman coal-fired power plant adopted by the EQC in 2009 as part of Oregon's Regional Haze Plan. DEQ's 2009 pollution control rules for Boardman were based on a remaining useful life for that facility through at least 2040. In the petition, PGE proposes an alternative approach for meeting federal regional haze requirements to install best available retrofit technology, as well as elimination of other pollution control requirements, all in conjunction with closing the Boardman coal-fired power plant on Dec. 31, 2020.

Under Oregon law, EQC must act within 90 days to either approve or deny the petition. The deadline for the commission to respond to the petition is July 1, 2010. If the commission grants the petition, DEQ would initiate rulemaking using PGE's proposed rule changes as the starting point for DEQ's proposed rule revision. If the commission denies the petition, EQC could then direct DEQ to initiate rulemaking based on a wider range of pollution control options as the starting point, consistent with an early closure of the plant. Either option would require a complete pollution control evaluation to meet federal regional haze requirements. DEQ supports early closure of the Boardman coal-fired power plant; however, the agency would like to explore a wider range of pollution control options consistent with an early closure date.

DEQ recommendation and EQC motion

DEQ recommends that the Oregon Environmental Quality Commission deny PGE's petition, and, following this action, direct DEQ to initiate rulemaking based on a wider range of pollution control options as the starting point for revising regional haze pollution controls consistent with an early closure of the plant.

Background and need for rulemaking

The Clean Air Act and federal regional haze program requires certain older industrial facilities, such as PGE Boardman, to install pollution controls that reduce haze pollution. EQC adopted rules in 2009 requiring new pollution controls for Boardman, including a requirement to install best available retrofit technology. Under PGE's petition, the early shutdown of the plant would avoid installing stringent controls designed to reduce sulfur dioxide emissions by 80 percent in 2014, and reduce nitrogen oxide emissions by an additional 40 percent in 2017. PGE's petition and analysis concludes that these controls would no longer be cost effective under a 2020 shut down scenario.

Effect of EQC action Denying the petition will allow DEQ to explore a wider range of pollution control options consistent with an early closure date that could be approvable by EPA.

Commission authority The commission has authority to take this action under ORS 468.020, 468A.025, 468A.035, 468A.310, 183.390, OAR 340-011-0046 and OAR 137-001-0070.

Stakeholder involvement DEQ has informed stakeholders of the agency's recommendation to EQC.

Public comment Written and oral public comments on DEQ's recommendation will be accepted until June 1, 2010. An additional opportunity for oral public comment will be provided at a public hearing scheduled at the commission's meeting in Lakeview on June 17, 2010.

Next steps DEQ would begin rulemaking, as noted above, based on the commission's decision regarding the petition, and direction. This rulemaking process would include stakeholder meetings, an advisory committee meeting, a public comment period, public hearings, and presentation of final proposed rules at the commission's December 2010 meeting.

Attachments

A. PGE Petition
B. DEQ Public Comment Notice

Available Upon Request

1. Legal Notice of Hearing

Approved:

Division: ______________________________

Report prepared by: David Collier
Phone: (503) 229-5177

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

April 2, 2010

BY HAND DELIVERY

Mr. Dick Pedersen
Director
Oregon Department of Environmental Quality
811 SW Sixth Ave
Portland, OR 97204

Re: Petition to Amend OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1)

Dear Mr. Pedersen:

In your role as Director of the Oregon Department of Environmental Quality ("Department") and representative of the Oregon Environmental Quality Commission ("Commission"), Portland General Electric Company ("PGE") is filing with you this petition to amend OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1). On June 19, 2009, the Commission adopted the Oregon Regional Haze Plan, which includes OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1). The Oregon Regional Haze Plan also includes an express statement that "Should PGE determine that the impact and cost of carbon regulations will require the closure of the PGE Boardman plant, PGE may submit a written request to the Department for a rule change." Oregon Regional Haze Plan at p. 202. This petition is in direct response to that invitation.

Granting this petition will ensure that emissions of visibility impairing pollutants are substantially reduced consistent with the goals of the Regional Haze Plan and the Clean Air Act. PGE's petition requests that the Department revise the BART/Reasonable Progress determination to require:

(1) Installation of pre-combustion NOx controls by July 1, 2011 (resulting in a 50 percent reduction in NOx emissions from current permit levels);

(2) Reduction of permitted SO_2 emissions from 1.2 lb/MMBtu heat input to 0.96 lb/MMBtu (a 20 percent reduction) no later than December 31, 2011;

(3) Compliance with an SO_2 emissions limit of 0.60 lb/MMBtu no later than July 1, 2014 (a 50 percent reduction from current permit levels); and,

(4) Closure of the Boardman Plant coal-fired boiler no later than December 31, 2020.

These measures will ensure a reduction in NOx emissions of nearly 50 percent in 2011, a reduction in the SO_2 emissions limit of exactly 50 percent by 2014, and end all emissions from the Boardman Plant boiler after 2020.

Mr. Dick Pedersen
April 2, 2010
Page 2

Granting this petition will serve the interests of Oregon's citizens in addition to improving visibility in Class I areas. Analysis conducted by PGE at the request of Oregon Public Utility Commission ("OPUC") Staff and other stakeholders in PGE's Integrated Resource Planning ("IRP") process, indicates that the most reasonable course of action, in terms of cost and risk, would be to close the Boardman Plant boiler in 2020, decades earlier than its planned life through 2040.

Adherence to this operating plan will benefit Oregonians and Oregon's environment by achieving significantly lower aggregate levels of emissions from the plant over time than would be allowed under the current rule. It will also reduce costs to PGE customers associated with emissions control retrofits and future carbon regulation, while capturing the front-loaded cost benefits of continued operation through 2020 and allowing a reasonable timeframe for development of reliable replacement resources with a smaller environmental footprint.

Accordingly, PGE is submitting an addendum to its IRP requesting that the OPUC acknowledge the cessation of Boardman Plant boiler operations in 2020. This approach reflects the high likelihood of carbon regulation in the near future and the cost of compliance with OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1). Approval of this petition to amend the BART/Reasonable Progress determination is necessary to enable PGE to implement its IRP proposal.

The proposed revisions to the Boardman Plant BART/Reasonable Progress determination will provide near-term reductions in visibility impairing pollutants while providing for closure of the Boardman Plant boiler by the end of 2020. This approach complies with BART while also allowing for an orderly transition away from coal-fired generation. Imposition of short term NOx and SO_2 control measures combined with closure of the Boardman Plant boiler in 2020, if allowed by the Commission, is the right choice for Oregon. It will provide the lowest cost and price stability of electricity for utility customers, while greatly reducing the level of air emissions in Oregon.

PGE looks forward to meeting with you and your staff to discuss this petition further.

Sincerely,

Stephen Quennoz
Vice President, Power Supply/Generation

BEFORE THE ENVIRONMENTAL QUALITY COMMISSION

OF THE STATE OF OREGON

IN THE MATTER OF: PORTLAND GENERAL ELECTRIC COMPANY, Petitioner.	PETITION TO PROMULGATE, AMEND, OR REPEAL OAR 340-223-0030(1)(b) AND (1)(c) and OAR 340-223-0040(1) PURSUANT TO OAR 340-011-0046

PETITION

1. Portland General Electric Company ("PGE" or "Petitioner") hereby petitions the Environmental Quality Commission (Commission) pursuant to OAR 340-011-0046 to amend OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) as detailed below.

2. Petitioner's address is as follows:

1 World Trade Center
121 SW Salmon Street, 17th Floor
Portland, OR 97204

3. Consistent with OAR 137-001-0070(1), Petitioner must identify the name and address of any other person known to the Petitioner to be interested in the rule. Petitioner is unable to identify with certainty all such parties, but has included as Exhibit A to this petition a list of those parties that commented on the Oregon Regional Haze Plan and so would appear to be interested in any changes to OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1). Additional parties may also be interested in any changes to these rules.

4. OAR 137-001-0070(1)(a) requires that Petitioner set forth the rule requested to be amended in full with matter proposed to be deleted and proposed additions shown by a method that clearly indicates proposed additions and deletions. Included as Exhibit B is an exact reproduction of the existing text of OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) with all proposed additions and deletions identified in redline format.

BASIS FOR PETITION

5. OAR 137-001-0070(1)(a) requires that Petitioner set forth facts or arguments in sufficient detail to show the reasons for and effects of the requested amendments to OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1).

6. On June 19, 2009, the Commission adopted the Oregon Regional Haze Plan, which includes OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1).

7. The Foster-Wheeler boiler located at the Boardman coal-fired power plant (Federal Acid Rain Program Facility ORISPL Code 6106) (the "Boardman Plant boiler") is jointly owned by PGE (65%), Idaho Power (10%), Power Resources Cooperative (10%) and Bank of America Leasing (15%). PGE is the exclusive operator of the Boardman Plant boiler.

8. OAR 340-223-0030(1)(b) and (1)(c) impose SO_2 and PM limits intended to reflect the Best Available Retrofit Technology ("BART") requirements of Clean Air Act Section 169A. OAR 340-223-0040(1) imposes NOx limits intended to reflect the "Reasonable Progress" requirements of Clean Air Act Section 169A. OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) apply exclusively to the Boardman Plant boiler. OAR 340-223-0030(1)(b) and (1)(c) require compliance by July 1, 2014; OAR 340-223-0040(1) requires compliance by July 1, 2017.

9. OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) were proposed based on the assumption that the Boardman Plant boiler would operate through approximately 2040.

10. A variety of considerations, including the likely imposition of regulations imposing significant costs on the emission of non-biogenic carbon support a decision to close the Boardman Plant boiler prior to 2040.

11. On December 17, 2008 and January 30, 2009, Petitioner submitted written comments to the Oregon Department of Environmental Quality ("Department") on proposed OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1), requesting that alternate limits

be placed in the rules reflective of potential earlier closure dates for the Boardman Plant boiler (2020 and 2029).

12. The Department presented to the Commission, and the Commission adopted, the Oregon Regional Haze Plan without the provisions requested by Petitioner providing for alternate limits reflective of closure dates prior to 2040. However, in Chapter 10 of the Oregon Regional Haze Plan, the Commission acknowledged that the cost of future greenhouse gas regulation in context with costs associated with complying with the limits in OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) "could be significant and may require Petitioner to evaluate cost-benefit factors affecting the future of the Boardman Plant, as part of the Oregon Public Utility Commission Integrated Resource Plan process." Oregon Regional Haze Plan at p. 155. In Chapter 12 of the Oregon Regional Haze Plan, the Commission 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." Oregon Regional Haze Plan at p. 202.

13. Petitioner has determined that there is a reasonable probability that the impact and cost of carbon regulations, alone or in combination with other factors, could require the closure of the Boardman Plant boiler. Therefore, Petitioner is petitioning the Commission to repeal OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) and adopt in their place the requirements that the Boardman Plant boiler (a) no later than December 31, 2011, cease burning coal that could result in SO_2 emissions in excess of 0.96 lb/MMBtu (annual average), (b) no later than June 30, 2014, cease burning coal that could result in SO_2 emissions in excess of 0.60 lb/MMBtu (annual average), and (c) no later than December 31, 2020, cease operation entirely.

14. Attached as Exhibit C is a BART/Reasonable Progress Analysis evaluating the technical and legal basis for the replacement of OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) with the requirements that the Boardman Plant boiler progressively decrease its SO_2 emissions and cease operations by no later than December 31, 2020. This analysis provides

the reasons for and effects of the requested amendments to the rules. Exhibit C also evaluates options for achieving the existing rules' substantive goals and presents a means of reducing the negative economic impacts of the existing rules on businesses.

15. OAR 137-001-0070(2)(b) requires that the Petitioner comment on the options for achieving the substantive goals of OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) while reducing the negative economic impact on businesses. The goal of OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) is to achieve the mandate of Section 169A of the federal Clean Air Act to reduce impacts to visibility in Class I areas to natural levels by 2064. OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) contribute to this goal by imposing extremely costly requirements on Petitioner and its co-owners. The several hundred million dollar capital cost and tens of millions of dollars in annual operating costs associated with attaining the limits in OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) will likely result in increased electricity costs for businesses served by the Boardman Plant boiler owners. As explained in more detail in Exhibit C, replacing OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) with the regulatory requirements that the Boardman Plant boiler progressively decrease its SO_2 emissions and close no later than December 31, 2020 will reduce the negative electricity rate impacts (i.e., economic impacts) of these requirements on businesses while achieving the substantive goals of OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) and Section 169A of the Clean Air Act to reduce impacts to visibility in Class I areas to natural levels by 2064.

16. OAR 137-001-0070(2)(b) requires that the Petitioner comment on the continued need for OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1). It is necessary that the Commission retain OAR 340-223-0030(1)(a) as that rule is the determination of BART for the Boardman Plant boiler for NOx. This regulation is already being implemented and will reduce the Boardman Plant boiler NOx emissions by thousands of tons annually. It is necessary that the Commission determine BART for SO_2 and PM and include that determination within Oregon's

regulations. However, there is no requirement that BART be fixed and not change in response to new information, as was made clear at page 202 of the Oregon Regional Haze Plan. Also, Section 169A(g)(7) of the federal Clean Air Act expressly requires that the Commission consider the remaining useful life of the Boardman Plant boiler as a separate factor in determining BART. There is no requirement at this time that the Commission establish Reasonable Progress based requirements for the Boardman Plant boiler and so there is no current federal or state requirement to maintain OAR 340-223-0040(1).

17. OAR 137-001-0070(2)(c) requires that the Petitioner comment on the complexity of OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1). These rules are simple to the extent that they impose readily identifiable emission limits on the Boardman Plant boiler. However, they are complex to the extent that they require formidable planning, development and implementation by Petitioner in order to retrofit the necessary controls for the Boardman Plant boiler by the specified deadlines. Replacing OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) with the requirements that the Boardman Plant boiler progressively decrease its SO_2 emissions and ultimately to cease operations no later than December 31, 2020 is a simpler requirement to implement and a simpler result for the public to understand. If Petitioner's requested modifications to these rules are promulgated by the Commission, the Boardman Plant boiler NOx and SO_2 emissions will drop dramatically between now and 2014 and will cease entirely starting just over 10 years from the date of this petition.

18. OAR 137-001-0070(2)(d) requires that the Petitioner comment on the degree to which OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) overlap, duplicate or conflict with other state or federal rules and with local government regulations. OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) arise from the Commission's efforts to address requirements under Section 169A of the federal Clean Air Act. Therefore, Petitioner does not believe they duplicate other state or federal rules. However, these rules overlap and potentially conflict with the Integrated Resource Planning ("IRP") requirements implemented by the Oregon

Public Utility Commission ("OPUC"). The IRP requires a holistic assessment of the future of the Boardman Plant as a component of the overall design and reliability of Petitioner's generation and supply portfolio. By requiring compliance with the limits in OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1), the Commission creates potentially conflicting requirements. Petitioner's goal is to synchronize the Commission's actions with the OPUC's actions to the extent possible by proposing the replacement of OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) with the requirements that the Boardman Plant boiler progressively decrease its SO_2 emissions and cease operations no later than December 31, 2020.

19. OAR 137-001-0070(2)(e) requires that the Petitioner comment on the degree to which technology, economic conditions, or other factors have changed in the subject area affected by OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) since the Commission adopted the rules. Since the time that these rules were adopted, significant domestic and international momentum has developed for the concept of imposing costs on the emission of carbon—particularly from coal-fired power plants. This change is evidenced by the adoption of the Copenhagen Accord on December 19, 2009 in which President Obama committed to achieving reductions in greenhouse gas emissions of between 14 and 17 percent by 2020. This change is further evidenced by EPA's declaration on March 29, 2010 that greenhouse gases will be considered regulated air pollutants under the Clean Air Act effective January 2, 2011. In addition, since the rules subject to this petition were adopted PGE has determined that if the Boardman Plant boiler is not operated after December 31, 2020, it should be possible to find sufficient reduced sulfur coal to comply with a 0.60 lb/MMBtu heat input SO_2 limit (half the current SO_2 limit) by no later than July 1, 2014. Utilization of reduced sulfur coal, in conjunction with the closure of the Boardman Plant boiler in 2020, would be consistent with the President's goal and new information regarding reduced sulfur coal availability. Both factors arose after OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) were adopted. In addition, since OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) were adopted on

June 19, 2009, PGE has engaged in a substantial IRP public process that includes examination of the increased economic impact that carbon regulation will have on the economic viability of the Boardman Plant boiler. Furthermore, since OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) were adopted on June 19, 2009, the U.S. Environmental Protection Agency has proposed and/or adopted multiple rules that will ultimately reduce NOx, SO_2 and PM emissions in Oregon and therefore enhance the visibility in the region's Class I areas (e.g., new NO_2 standards, new mobile source standards).

REQUESTED RELIEF

20. For the reasons stated above, Petitioner believes that it is consistent with the goals of the Oregon Regional Haze Plan, Section 169A of the federal Clean Air Act, federal and state carbon reduction goals, and the economic and environmental protection of Oregon's citizens to replace OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) with the requirements that the Boardman Plant boiler progressively decrease its SO_2 emissions and ultimately cease operation no later than December 31, 2020.

21. Therefore, Petitioner requests that the Commission revise OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1) as specified in Exhibit B to this petition.

Respectfully submitted April 2, 2010.

Stephen Quennoz by [signature] jps

Stephen Quennoz
Vice President, Power Supply/Generation

EXHIBIT A

List of People and Organizations Submitting Comments (by Commenter Number)

Letters

Letters includes written comments received by mail, at public hearings, and attached to emails.

Ref. No.	Name	Location	Affiliation or Organization	Submit Date
1.	Ralph Sampson, Jr. Tribal Council Chairman	Pendleton	Confederated Tribes and Bands of the Yakima Nation	1/30/2009
2.	Samuel N. Penney Chairman	Lapwai, ID	Nez Perce Tribal Executive Committee	1/30/2009
3.	Antone Minthorn John Cox	Toppenish, WA	Confederated Tribes of the Umatilla Indian Nation	1/30/2009
4.	Jurgen A. Hess	Hood River		1/13/2009
5.	Tom Garefalo	(not stated)		1/26/2009
6.	Emily S. St. John	Lake Oswego		1/07/2009
7.	Cynthia Hovezak	Carson, WA		1/23/2009
8.	Tom Wood	The Dalles		1/23/2009
9.	Tassy Mack	Hood River		1/23/2009
10.	Robin Bloomgarden	Portland		1/07/2009
11.	Susan Gabay	Mosier		1/26/2009
12.	Arlen L. Sheldrake	Portland		1/27/2009
13.	John Wood	Hood River		1/26/2009
14.	Hugh B. McMahan	Mount Hood		1/29/2009
15.	Judith Werner	Lake Oswego		1/30/2009
16.	Phil Swaim & Sheila Dooley	The Dalles		1/28/2009
17.	Aubrey E. Baldwin [2] Allison LaPlante Tom Buchele	Portland	Pacific Environmental Advocacy Group	1/30/2009
18.	Joyce Reinig, Chair	White Salmon, WA	Columbia River Gorge Commission	1/29/2009
19.	Peter Cornelison, President	Hood River	Hood River Valley Residents Committee	1/13/2009
20.	Maye Thompson	Portland	Oregon Physicians for Social Responsibility	1/26/2009
21.	Michael Lang	Portland	Friends of the Columbia Gorge	1/6/2009
22.	Arya Behbehani-Divers [2] Ray Hendricks	Portland	Portland General Electric Company	12/17/2008 1/30/2009
23.	Sandra McDonough President & CEO	Portland	Portland Business Alliance	1/26/2009
24.	John Ledger Vice President	Salem	Associated Oregon Industries	1/29/2009
25.	Ted Ferrioli State Senator	Salem	Oregon State Senate	1/22/2009
26.	David Nelson State Senator	Salem	Oregon State Senate	1/26/2009
27.	Gary Neal General Manager	Boardman	Port of Morrow	1/12/2009
28.	Lee Beyer, Chairman John Savage, Commissioner Ray Baum, Commissioner	Salem	Public Utilities Commission	1/27/2009

29.	Jean DeMaster Executive Director	Portland	Human Solutions, Inc.	1/30/2009
30.	Jack Scott General Manager	Portland	Eagle Foundry Company	1/23/2009
31.	Raymond Burstedt President	Portland	SEDCOR	1/21/2009
32.	Travis Eri Business Manager	Portland	International Brotherhood of Electrical Workers, Local 125	1/26/2009
33.	Robert Ford President & CEO	Portland	Solaicx	1/26/2009
34.	Corky Collier Executive Director	Portland	Columbia Corridor Association	1/28/2009
35.	Brian Konen Plant Manager	West Linn	West Linn Paper Company	1/28/2009
36.	John M. Endicott President	Portland	Building & Construction Trades Council	1/29/2009
37.	Clif Davis Business Manager	Portland	International Brotherhood of Electrical Workers, Local 48	1/29/2009
38.	Carla McLane Planning Director	Irrigon	Morrow County Planning Department	1/30/2009
39.	Tom Chamberlain President	Salem	Oregon AFL-CIO	1/29/2009
40.	Matt Felton President	Portland	Westside Economic Alliance	1/28/2009
41.	Ryan Deckert President	Tigard	Oregon Business Association	1/29/2009
42.	Bob Jenks Executive Director	Portland	Citizen's Utility Board of Oregon	1/30/2009
43.	Michael T. McLaran CEO	Salem	Salem Chamber of Commerce	1/29/2009
44.	Michael B. Early Executive Director	Portland	Industrial Customers of Northwest Utilities	1/30/2009
45.	Jim Trost	Salem	Oregon Department of Forestry	1/28/2009
46.	Mike Dykzeul Director Forest. Protection	Salem	Oregon Forest Industries Council	1/27/2009
47.	Richard Albright Director Mahbubul Islam Director	Seattle, WA	EPA Region 10	12/11/2008 1/30/2009
48.	Jean M. Hadley	Mosier	City of Mosier	1/25/2009
49.	Arthur Babitz Mayor	Hood River	City of Hood River	1/27/2009
50.	Mary Wagner Regional Forester	Portland	U.S. Forest Service Pacific Northwest Region	1/29/2009
51.	Robert D. Elliot Executive Director	Vancouver, WA	Southwest Clean Air Agency	1/6/2009
52.	John Bunyak [2] Chief, Policy, Planning and Permit Review Branch	Denver, CO	National Park Service	1/30/2009
53.	Christine L. Shaver [2] Chief, Air Resources Division Sandra V. Silva Chief, Branch of Air Quality	Denver, CO	National Park Service U.S. Fish & Wildlife Service	1/30/2009
54.	Kevin Lynch [2]	Boulder, CO	Environmental Defense Fund	1/30/2009

	Stephanie Kodish	Knoxville, TN	National Parks Conservation Association	
55.	Sallie Schullinger-Krause Program Director	Portland	Oregon Environmental Council	1/30/2009
56.	Keith Peal	Beaverton	Baker Rock Resources	1/27/2009
57.	Lee Elwood	(not stated)		1/12/2009
58.	Scott Starr	Wilsonville	Wilsonville Chamber of Commerce	1/27/2009
59.	Deanna Palm	Hillsboro	Greater Hillsboro Area Chamber of Commerce	1/27/2009
60.	Tamra J. Mabbott	Hermiston		1/29/2009
61.	Roger W. Rees Executive Director	Tualatin	Oregon Home Energy Assistance Team (HEAT)	1/29/2009

Oral Testimony

Location represents the site of the public hearing. Those who provided written and oral testimony are listed under Letters. For complete list of all who testified, see Attachment C *DEQ Hearing Officer's Report on Public Hearings*.

62.	Tom Wood	Portland	Associated Oregon Industries	1/6/2009
63.	Andrew Hawley	Portland	Northwest Environmental Defense Council	1/6/2009
64.	Brian Pasko	Portland	Sierra Club	1/6/2009
65.	Alan T. Edwards	Portland		1/6/2009
66.	Gordon Fulks	Portland		1/6/2009
67.	Jan Groh	Portland		1/6/2009
68.	David Rupar	Portland		1/6/2009
69.	Terry Tallman	Hermiston	Morrow County Judge	1/12/2009
70.	Joseph Kelsey	The Dalles		1/13/2009
71.	Lauren Goldberg	The Dalles	Columbia Riverkeeper	1/13/2009
72.	Rachael Pecore	The Dalles	Columbia Riverkeeper	1/13/2009
73.	David Berger	The Dalles	Oregon Conservancy Foundation	1/13/2009
74.	Dan Richardson	The Dalles		1/13/2009
75.	Jodi Tepoel	The Dalles		1/13/2009
76.	John Carstensen	The Dalles	Idaho Power Company	1/13/2009
77.	Jules Burton	The Dalles		1/13/2009
78.	Mark Nelson	The Dalles		1/13/2009
79.	Jessica Kinder	The Dalles		1/13/2009
80.	Rosemary Ross	The Dalles		1/13/2009
81.	John Nelson	The Dalles		1/13/2009
82.	Joel Kabakov	The Dalles		1/13/2009

Emails

Those who provided written testimony along with an email are listed above under Letters.

83.	Aleita Hass-Holcombe		12/26/2008
84.	Anne Moore		1/30/2009
85.	Brent Brelje		1/6/2009
86.	Carol Crawford		1/20/2009
87.	Carole L. Myers		1/25/2009
88.	Chris Carvalho		1/12/2009
89.	Cindy Allen		1/23/2009
90.	Colleen O'Donnell		1/21/2009
91.	Daniel Curtis		1/20/2009
92.	Darlene Wood		1/23/2009
93.	Darryl Usher		1/20/2009

94.	Dave Bronson		1/19/2009
95.	David Breen		1/4/2009
96.	Dr. David Farrell		1/20/2009
97.	David Mildrexler		1/19/2009
98.	David Shapiro		1/20/2009
99.	Dean Mason		1/29/2009
100.	Dean Myerson		1/28/2009
101.	Dinda Evans		1/5/2009
102.	Don Coats		1/13/2009
103.	Don Hall		1/19/2009
104.	Don Hill		1/4/2009
105.	Elke Geiger		1/26/2009
106.	Eric Swehla		12/23/2008
107.	Erik Westerholm		1/6/2009
108.	Gary J. Imbrie		1/23/2009
109.	Geert Aerts		1/19/2009
110.	George W. & Margo Earley		1/23/2009
111.	Granella Thompson		1/13/2009
112.	Heather Moore		1/22/2009
113.	Jack and Cindy Williams		1/10/2009
114.	James Wells		1/19/2009
115.	Jason Cheek		1/29/2009
116.	Jason Stillman		1/29/2009
117.	Jay W. Russell		1/6/2009
118.	Jeffrey Block		1/19/2009
119.	Jennifer Sturm		1/29/2009
120.	Jerry & Diane Cheek		1/24/2009
121.	Jerry Waters		12/23/2008
122.	Jim Minick		1/28/2009
123.	John E. McCann		12/25/2008
124.	John Gogol		1/28/2009
125.	Judith Arcana		1/19/2009
126.	Kathleen Fitzpatrick		1/3/2009
127.	Kent Buhl		1/29/2009
128.	Kris Gann		1/13/2009
129.	Kristin Anderson		1/21/2009
130.	Larry Bartlemay		1/30/2009
131.	Levin Nock		12/23/2008
132.	Louise Squire		1/12/2009
133.	Lynn Bergeron		1/27/2009
134.	Margaret Murdock		12/23/2008
135.	Marion Hansen		1/19/2009
136.	Mark Mason		1/28/2009
137.	Mary McCracken		1/9/2009
138.	Melody Shapiro		1/28/2009
139.	Michael D. Holcomb		1/29/2009
140.	Mildred Estrin		12/23/2008
141.	Mimsi Fox		1/19/2009
142.	Natalie Arndt		1/10/2009
143.	Nick Engelfried		12/26/2008
144.	Nick Kraemer		1/15/2009
145.	Nick Littlejohn		1/27/2009
146.	North Cheatham		1/29/2009

147.	Paul Woolery		1/17/2009
148.	Pat Hazlett		1/13/2009
149.	R. Moulton		1/28/2009
150.	Randy Curtis		1/29/2009
151.	Robert Hamm		1/3/2009
152.	Ron Mager		1/9/2009
153.	Ronald S Bray		1/29/2009
154.	Rose Engelfried		12/24/2008
155.	Sandra Coulson		1/14/2009
156.	Sandra Lilligren		1/8/2009
157.	Shelley Oates		1/24/2009
158.	Steve Amy		1/28/2009
159.	Steve Locke		1/6/2009
160.	Steve Snyder		1/5/2009
161.	Susan Drew		1/29/2009
162.	Teri Miller		1/8/2009
163.	Tiffany Brown		1/20/2009
164.	Tim Davidson		1/25/2009
165.	Tina Castañares		1/17/2009
166.	Tina Engelfried		12/23/2008
167.	Tony Veldhuizen		1/9/2009
168.	Group 1 - (1028 form letters) [3]		-
169.	Group 2 - (7 form letters) [3]		-
170.	Group 3 - (15 form letters) [3]		-

[2] Commenters who provided attachments (available upon request)

[3] For the list of commenters in this group, see Attachment 1 (available upon request). Numbers in **bold** reflect more than one commenter.

EXHIBIT B

340-223-0030

BART Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106)

(1) Emissions limits:

(a) On and after July 1, 2011, nitrogen oxides emissions must not exceed 0.28 lb/mmBtu heat input as a 30-day rolling average and 0.23 lb/mmBtu heat input as a 12-month rolling average.

(A) If it is demonstrated by July 1, 2012 that the emission limits in (a) cannot be achieved with combustion controls, the Department may grant an extension of compliance to July 1, 2014.

(B) If an extension is granted, the nitrogen oxides emissions must not exceed 0.23 lb/mm Btu heat input as a 30-day rolling average on and after July 1, 2014.

~~(b) On and after July 1, 2014, sulfur dioxide emissions must not exceed 0.12 lb/mmBtu heat input as a 30-day rolling average.~~

(b) On and after January 1, 2012, sulfur dioxide emissions must not exceed 0.96 lb/mmBtu heat input as a 12-month rolling average.

(c) On and after July 1, 2014, sulfur dioxide emissions must not exceed 0.60 lb/mmBtu heat input as a 12-month rolling average.

(~~c~~d) On and after July 1, 2014, particulate matter emissions must not exceed ~~0.012~~0.040 lb/mmBtu heat input as determined by compliance source testing.

(~~de)~~ The emission limits in (a) through (~~c~~d) above do not apply during periods of startup or shutdown.

(2) Compliance demonstration. Using the procedures specified in section (3) of this rule:

(a) Compliance with a 30-day rolling average limit must be demonstrated within 180 days of the compliance date specified in section (1) of this rule.

(b) Compliance with a 12-month rolling average must be demonstrated within ~~12~~13 months of the compliance date specified in section (1) of this rule.

(3) Compliance Monitoring and Testing

(a) Compliance with the emissions limits in (1)(a), (b) and (~~b~~c) must be determined with a continuous emissions monitoring system (CEMS) installed, operated, calibrated, and maintained in accordance with the acid rain monitoring requirements in 40 CFR Part 75 as in effect on ~~June 19, 2009~~August 18, 2010.

(A) The hourly emission rate in terms of lb/mmBtu heat input must be recorded each operating hour, including periods of startup and shutdown.

(B) The daily average emission rate must be determined for each boiler operating day using the hourly emission rates recorded in (A), excluding periods of startup and shutdown.

(C) 30-day rolling averages must be determined using all daily average emissions rates recorded in (B) whether or not the days are consecutive.

(D) 12-month rolling averages must be determined using calendar month averages based on all daily averages during the calendar month.

(b) Compliance with the particulate matter emissions limit in (1)(~~c~~d) must be determined by EPA Methods 5 and 19 as in effect on ~~June 19, 2009~~August 18, 2010.

(A) An initial test must be conducted by January 1, 2015.

(B) Subsequent tests must be conducted in accordance with a schedule specified in the Oregon Title V Operating Permit, but not less than once every 5 years.

(C) All testing must be performed in accordance with the Department's Source Sampling Manual as in effect on August 18, 2010~~June 19, 2009~~.

(4) Notifications and Reports

(a) The Department must be notified in writing within 7 days after any control equipment (including combustion controls) used to comply with emissions limits in section (1) begin operation.

(b) For NOx ~~and SO2~~ limits based on a 30-day rolling average, a compliance status report, including CEMS data, must be submitted within 180 days of the compliance dates specified in section (1).

(c) If applicable, a compliance status report for the 12-month rolling average NOx limit in section (1)(a) must be submitted by August 1, 2012.

(d) For sulfur dioxide limits a compliance status report for the 12-month rolling average SO_2 limit in section (1)(b), must be submitted by February 1, 2013 and a compliance status report for the 12-month rolling average sulfur dioxide limit in section (1)(c), must be submitted by August 1, 2015.

(~~d~~e) For particulate matter, a compliance status report, including a source test report, must be submitted within 60 days of completing the initial compliance test specified in section (3)(b).

340-223-0040

Additional ~~NOx~~ Requirements for the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106)

On and after ~~July~~ December 31, 20~~17~~20, the Foster-Wheeler Boiler at the Boardman Coal-Fired Power Plant (Federal Acid Rain Program Facility ORISPL Code 6106) must cease operations.

~~nitrogen oxides emissions must not exceed 0.070 lb/mmBtu heat input, excluding periods of startup and shutdown.~~

~~(1) Compliance with the NOx emissions limit must be determined with a continuous emissions monitoring system in accordance with OAR 340-223-0030(2) and (3).~~

(1~~2~~) The Department must be notified in writing within 7 days after the boiler ceases operation.~~any control equipment used to comply with the emission limit begins operation.~~

~~(3) A compliance status report, including CEMS data, must be submitted by January 1, 2018.~~

EXHIBIT C

BEST AVAILABLE RETROFIT TECHNOLOGY/ REASONABLE PROGRESS ANALYSIS

Portland General Electric

Boardman Plant

Best Available Retrofit Technology (BART) / Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative

Black & Veatch Project: 144449
Black & Veatch File No.: 40.0000

April 2, 2010

BLACK & VEATCH
Building a world of difference.

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Table of Contents

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Tables

Figures

Table of Contents (Continued)

Figures (Continued)

Acronym List

A/C	Air-to-Cloth
AFDC	Allowance for Funds During Construction
ASN	Ammonium Sulfate Nitrate
BART	Best Available Retrofit Technology
Btu or Btu	British Thermal Unit
CaS	Calcium Sulfide
CCS	Clean Combustion System
CDS	Circulating Dry Scrubber
CO	Carbon Monoxide
CRGNSA	Columbia River Gorge National Scenic Area
CUECost	Coal Utility Environmental Cost
DCS	Distributed Control System
DEQ	Department of Environmental Quality
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FF	Fabric Filter
FGD	Flue Gas Desulfurization
ID	Induced Draft
IFGR	Induced Flue Gas Recirculation
LNB	Low NO_x Burners
LNB/MOFA	Low NO_x Burners with Modified Overfire Air
NLNB/MOFA/SNCR	New Low NO_x Burners with Modified Overfire Air and Selective Noncatalytic Reduction
NLNB/MOFA/SCR	New Low NO_x Burners with Modified Overfire Air and Selective Catalytic Reduction
$Mg(OH)_2$	Magnesium Hydroxide
MMBtu or MMBtu	Million (10^6) British Thermal Units
MW	Megawatt
N_2O_5	Nitrogen Pentoxide
NH_3	Ammonia
NO_x	Nitrogen Oxides
OFA	Overfire Air
O&M	Operating and Maintenance
PGE	Portland General Electric

PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
PRB	Powder River Basin
RSCR	Reduced Sulfur Coal Restriction
SCR	Selective Catalytic Reduction
SNCR	Selective Noncatalytic Reduction
Semi-Dry FGD	Semi-Dry Flue Gas Desulfurization
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compounds
WESP	Wet Electrostatic Precipitator
WFGR	Windbox Flue Gas Recirculation

Executive Summary

The Boardman Plant is a 584 megawatt (MW) net pulverized coal fired steam electric plant of more than 250 million British thermal unit (MMBtu) per hour heat input located near Boardman, Oregon, about 150 miles east of Portland. The plant obtained its construction authorization on February 27, 1975 from the Oregon Nuclear and Thermal Energy Council (NTEC).

On July 6, 2005, the Environmental Protection Agency (EPA) issued its final *Regional Haze Regulations and Guidelines for Performing Best Available Retrofit Technology (BART) Determinations*. These rules/guidelines established a procedure for identifying those sources that must retrofit their existing facilities with BART and for determining what constitutes BART. The purpose of the BART program is to require controls, where appropriate, for facilities that were not subject to the new source review requirements of the 1977 Clean Air Act Amendments. Specifically, the BART rules apply exclusively to sources within one of the enumerated source categories that were in existence prior to August 7, 1977. Because the Boardman Plant coal-fired boiler (the Boardman Plant boiler) is a steam electric plant of more than 250 MMBtu per hour heat input that was in existence (as that term is defined by EPA) before August 7, 1977, it was identified by the Oregon Department of Environmental Quality (DEQ) as a BART source.

On November 2, 2007, PGE submitted a BART analysis to DEQ evaluating the available NO_x, PM and SO_2 retrofit controls for the Boardman Plant boiler. This analysis assumed that the Boardman Plant boiler would operate for the rest of its physical life, i.e., until at least 2040. PGE noted that the analysis would require revision if it was determined that a shorter boiler life was appropriate. On December 1, 2008, the DEQ published its proposed BART determination for the Boardman Plant boiler. During the public comment period, PGE requested that DEQ consider allowing PGE to forego certain controls if the company committed to cease operation of the Boardman Plant boiler by dates certain.

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

Table ES-1
Oregon Regional Haze Plan Requirements for the Boardman Plant Boiler

Limit (Assumed Control)	Installation Deadline	Authority
0.28 lb NO_x/MMBtu - 30 day rolling average 0.23 lb NO_x/MMBtu - Annual average (Low-NO_x 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 NO_x/MMBtu (SCR)	7/1/2017	Reasonable Progress

*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 NO_x limit changes to 0.23 lb/MMBtu as a 30 day rolling average.

In adopting these BART/Reasonable Progress 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 NO_x 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." Regional Haze Plan at p. 155. 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." Regional Haze Plan at p. 202. Thus there was explicit recognition that PGE could petition DEQ for reconsideration of the BART and Reasonable Progress rules if external factors such as carbon regulation would result in early plant closure.

This revised BART/Reasonable Progress analysis was undertaken in response to DEQ's express commitment to consider a change to the BART and Reasonable Progress requirements. While specific legislation has not yet passed Congress, PGE believes that federal regulation of carbon from coal-fired power plants is likely and has therefore incorporated carbon costs in evaluating the future of the Boardman Plant in its Integrated Resource Plan (IRP) before the Oregon Public Utility Commission (OPUC). PGE's IRP analysis shows that the least-cost, least-risk option for its customers is for the Company to operate the Boardman Plant boiler for its full lifetime if the BART and Reasonable Progress controls are all installed. In response to requests from IRP stakeholders and OPUC staff, PGE has recently conducted additional analysis that suggests that a better option for its customers, in terms of both cost and risk could be to cease operations by the end of 2020; this option would require DEQ to revise the BART and Reasonable Progress regulations to delete OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1). Therefore, PGE is submitting this revised BART/Reasonable Progress analysis to request that DEQ revise the Regional Haze Plan accordingly.

Basis of Analysis

This analysis is broken into two sequential stages. First, BART was determined based on the Boardman Plant boiler as it currently exists in accordance with the five-step process identified in the EPA's *Regional Haze Regulations and Guidelines for Performing BART Determinations* (40 CFR Part 51, Appendix Y). Second, Reasonable Progress controls were analyzed based on the Boardman Plant boiler configuration once the boiler is compliant with the BART emission limits. Both analyses were conducted assuming that the Boardman Plant boiler will cease operations by the end of 2020.

The steps followed in the BART and Reasonable Progress analyses were consistent with the requirements of Clean Air Act Section 169A. In Step 1, available NO_x, SO_2, and PM retrofit control technologies were identified for the Boardman Plant boiler. In Step 2, this list was shortened by eliminating those technologies that are not technically feasible. In Step 3, the control effectiveness of each technically feasible control technology was evaluated. Based on this evaluation, the technologies were ranked in order of effectiveness. In Step 4, the cost, energy, and environmental impacts were evaluated for each technically feasible control technology. As mandated by the Clean Air Act the remaining life of the plant was considered as a stand-alone factor. The Reasonable Progress analysis built upon the BART analysis and added the additional analytical step of considering the time necessary for compliance. In the final step of the BART analysis, the visibility improvements associated with the top-ranked options were evaluated consistent with the modeling protocol approved by DEQ on January 18, 2007 and amended on August 28, 2007. Visibility improvement is not one of the considerations mandated by the Clean Air Act for the Reasonable Progress analysis.

The conclusions drawn from these analyses are summarized below.

NO_x Control Selection

BART NO_x Control Analysis

PGE does not believe that any change to the BART NO_x determination reflected in OAR 340-223-0030(1)(a) is merited. PGE is in the process of installing new low NO_x burners and a modified over-fire air system on the Boardman Plant boiler for NO_x control. These controls are expected to enable the Boardman Plant boiler to meet the BART NO_x limits in OAR 340-223-0030(1)(a) by July 1, 2011. These technologies are expected to reduce the NO_x emission levels for the Boardman Plant boiler from a baseline level of 0.43 lb NO_x/MMBtu to 0.23 lb NO_x/MMBtu (annual average).

Selective non-catalytic reduction (SNCR) equipment is planned as a contingency in the event that combustion controls cannot meet the BART NO_x limits and a compliance extension is requested. SNCR was considered as an additional interim control measure in the event that the combustion controls are capable of achieving the BART NO_x limits currently in the Regional Haze Plan. If the combustion controls alone reached the BART NO_x limits, then SNCR could potentially enable the Boardman Plant to further reduce NO_x emissions to as low as 0.19 lbs/MMBtu (annual average). However, in light of the negative impacts identified by the Department in relation to SNCR (e.g., ammonia storage concerns, impacts associated with ammonia slip, slag impacts and additional water consumption), PGE concluded that SNCR should not be the basis for setting more restrictive BART NO_x limits in the event that the combustion controls achieve the NO_x limits in OAR 340-223-0030(1)(a).

In conclusion, PGE suggests that the Department retain the current BART NO_x limits and deadlines in OAR 340-223-0030(1)(a) as nothing changes in the prior analysis as a result of accelerating the Boardman Plant boiler closure date to 2020.

Reasonable Progress NO_x Control Analysis

Based on the revised analysis, PGE believes that the Reasonable Progress NO_x requirements should be revised. The Regional Haze Plan BART NO_x limits are currently based on the 2011 installation of new low NO_x burners (NLNB) and a modified over-fire air system (MOFA). The Reasonable Progress NO_x limits are based on the 2017 installation of SCR. For the reasons stated below, and contingent on the addition of a requirement to OAR 340-223-0040 requiring that the Boardman Plant boiler cease operating no later than December 31, 2020, a Reasonable Progress requirement to meet 0.070 lb/MMBtu NO_x (i.e., the addition SCR) in 2017 cannot be justified. Therefore, the current requirement in OAR 340-223-0040 should be replaced with regulatory language requiring that the Boardman Plant boiler cease operation no later than December 31, 2020.[1]

PGE believes that the Reasonable Progress limits established in OAR 340-223-0040 should be replaced with a requirement that the Boardman Plant boiler cease operation by December 31, 2020. The factors mandated by the Clean Air Act do not justify establishing Reasonable Progress limits more stringent than those established through BART in light of the premature closure of the Boardman Plant boiler. The only technologies identified during the available control analysis that could be added to supplement the BART controls through Reasonable Progress are SNCR and SCR.[2] Both technologies were evaluated against the statutory factors mandated for determining Reasonable Progress controls and neither was found appropriate.

The energy and nonair quality impacts of SNCR and SCR support a conclusion that neither technology should be required as a Reasonable Progress control. Both SNCR and SCR have impacts that are more severe than those associated with combustion controls alone. Both technologies include additional fans, pumps and other electrical equipment that consume considerable energy, reducing the efficiency of the plant. In addition, the nonair quality environmental impacts, including ammonia slip, ammonia storage, and hazardous material disposal during SCR catalyst replacement, are significant. A direct impact of employing SCR is that the cost is so high that it would likely require utilization of the post-combustion controls for their full life (until approximately 2040) in order to achieve a reasonable cost recovery period. Operating the plant until 2040 would result in considerable additional emissions of greenhouse gases which are believed to contribute to climate change. By substituting closure in 2020 for installation of post-combustion NO_x controls, PGE would achieve the significant non-air quality environmental benefit of eliminating approximately 5,000,000 million tons of carbon dioxide emissions annually. These factors support the conclusion that neither SNCR nor SCR is an appropriate Reasonable Progress control technology.

The cost of compliance criterion similarly fails to support selecting SNCR or SCR as a Reasonable Progress control. The economic impacts associated with SCR are considerable—much higher than the cost of compliance associated with the BART NO_x limits in the Regional Haze Plan. The planned NLNB/MOFA are estimated to have

[1] PGE is currently exploring the potential to repower the Boardman Plant boiler utilizing alternative fuels. At this time such fundamental changes are still in the conceptual phase and there is no certainty that they will be technically feasible. Therefore, the potential to repower the boiler using an alternative fuel such as biomass is not addressed in this analysis. However, if such an innovative repowering alternative were identified, PGE respectfully requests that the Department be willing to reevaluate its Regional Haze plan to enable such an innovative strategy.

[2] This analysis assumes that the Boardman Plant is able to comply with the BART NO_x limits without the need for supplementary controls. If that is not the case, then SNCR (or comparable innovative controls) would already be installed pursuant to BART.

capital costs of $35.7 million. The total capital cost associated with adding SCR to the (then) existing NLNB/MOFA system is approximately $192 million. Operating costs associated with SCR are similarly much higher than the operating costs associated with maintaining the NLNB/MOFA system required by BART. ($6.1 million per year for NLNB/MOFA/SCR as opposed to $0.7 million per year for NLNB/MOFA). As a result, the cost of imposing SCR as Reasonable Progress equates to over $14,500 per ton of NO_x controlled. This is well outside the cost of compliance associated with Reasonable Progress determinations in other states and well outside the range of what is a reasonable cost. While the costs associated with SNCR are considerably lower than those associated with SCR, they still contribute to the overall conclusion that SNCR should not be considered a Reasonable Progress control.

Consideration of the remaining useful life of the Boardman Plant boiler also supports the conclusion that Reasonable Progress should not require NO_x limits more stringent than those reflecting combustion controls. Section 169A of the Clean Air Act mandates that DEQ take into account the remaining useful life of the source as a criterion coequal with the other factors (e.g., visibility improvement). The EPA Guidelines suggest accounting for remaining useful life as a component of the cost of compliance. This has been done in the assessment summarized above. However, Congress expressly identified the remaining useful life of the plant as a criterion distinct and separate from the cost of compliance criterion. The Department recognized in the Regional Haze Plan that it might not be appropriate to require costly post-combustion controls if the Boardman Plant boiler were required to cease operation prematurely. See, e.g., Regional Haze Plan at 155-156. Consistent with these statements, SCR was appropriately not considered as BART and should not be considered as Reasonable Progress if PGE agrees to a regulatory requirement that the Boardman Plant boiler cease operations no later than December 31, 2020. Similarly, SNCR should not be required as a Reasonable Progress control if the combustion controls alone are capable of attaining the BART limits.

Visibility improvement is not a Reasonable Progress criterion, but even if it was considered it would offer only marginal support for requiring SCR or SNCR as a Reasonable Progress control. The addition of either SNCR or SCR would result in additional NO_x reductions beyond those achieved by the BART NO_x controls.[3] Computer modeling indicates that these supplementary reductions would result in slightly improved visibility. However, while the BART controls will improve visibility in Mt. Hood and Hells Canyon (Δdv) by 25.0 percent, the addition of SNCR will only increase that

[3] This evaluation assumes that the combustion controls will be adequate to meet the BART NO_x limits and that the contingency provisions of OAR 340-223-0030(1)(a)(A) and (B) will not be triggered. If this is not the case, the Boardman Plant boiler will presumably already be employing SNCR as a BART control and it can be eliminated from consideration under Reasonable Progress.

improvement to 28.8 percent and the addition of SCR will only increase that improvement to 36.8 percent. Also, as EPA recognized in the 2005 preamble, the modeling system required for evaluating visibility impacts magnifies and overstates those improvements. Therefore, the incremental improvement achieved between the combustion NO_x controls (BART) and the NO_x controls incorporating SNCR or SCR (Reasonable Progress) is not, by itself, determinative. Furthermore, the Clean Air Act is explicit as to what criteria must be considered in determining Reasonable Progress controls and the degree of improvement in visibility is not one of the enumerated criteria. As a result, visibility improvement is not an adequate basis for overcoming the conclusion reached when considering the statutory Reasonable Progress factors that SCR and SNCR are not Reasonable Progress controls.

Therefore, PGE proposes that the Department revise the Regional Haze Plan to replace the Reasonable Progress NO_x limits in OAR 340-223-0040 with a requirement that PGE cease operating the Boardman Plant boiler no later than December 31, 2020.[4] This approach is consistent with the statutory criteria and will enable DEQ to rely on plant closure as part of its long term strategy to achieve its Reasonable Progress goals.

SO_2 Control Selection

SO_2 BART Control Analysis

Based on this revised analysis, PGE believes that the BART SO_2 requirements should be revised to require conditions not considered in the previous BART analysis. The Boardman Plant boiler already utilizes exclusively low sulfur coal so as to minimize SO_2 emissions resulting in a modeling baseline SO_2 emission rate of 0.81 lb/MMBtu. The prior BART analysis considered only post-combustion controls, all of which carry with them significant impacts. The Regional Haze Plan BART SO_2 limits are currently based on the 2014 installation of semi-dry scrubbers. No controls beyond continued use of low sulfur coal and operation of the scrubbers were considered necessary as a result of the Reasonable Progress analysis. PGE has reassessed its BART analysis for the Boardman Plant boiler to include interim coal sulfur limits that could provide additional SO_2 emissions reductions in lieu of post-combustion controls. Consideration of implementation of stepwise reduced sulfur coal limits in 2011 and 2014, in conjunction with a requirement to cease operation of the Boardman Plant boiler in 2020, presents a

[4] Nothing in the Clean Air Act grants DEQ the authority to require cessation of operation of the Boardman Plant boiler as a BART or Reasonable Progress control technology. However, PGE may propose an early closure date that is then taken into account in establishing BART and Reasonable Progress controls. This revised analysis assumes that PGE is willing to accept a requirement that it cease operation of the Boardman Plant boiler by December 31, 2020. However, if DEQ concludes that either BART or Reasonable Progress requires SCR, FGD or upgraded PM controls, then PGE expressly withdraws this analysis and any consideration of premature closure of the plant as an element of this analysis.

compelling alternative to the current BART requirements in OAR 340-223-0030(1)(b). For the reasons summarized below, when this BART alternative is considered, a BART requirement to meet 0.12 lb/MMBtu SO_2 (i.e., the addition of semi-dry scrubbers) in 2014 based on operation of the Boardman Plant boiler through 2040 cannot be justified. Therefore, the current requirement in OAR 340-223-0030(1)(b) should be replaced with regulatory language requiring that the Boardman Plant boiler use coal with an annual average sulfur dioxide emissions not to exceed 0.96 lb/MMBtu (annual average) by December 31, 2011 and 0.60 lb/MMBtu (annual average) starting on July 1, 2014 and requiring that the Boardman Plant boiler cease operation no later than December 31, 2020. No additional Reasonable Progress requirements are justified. This BART determination will require that PGE reduce the allowable level of sulfur dioxide emissions by 20 percent in 2011 and 50 percent in 2014.

The statutory factors do not support requiring semi-dry scrubbers as BART controls if the Boardman Plant boiler is required to reduce its SO_2 emissions limit by 20 percent in 2011 and 50 percent by July 1, 2014 and also to cease operation no later than December 31, 2020. Clean Air Act section 169A(g)(7) requires that in establishing BART, DEQ consider the cost of compliance, the energy and nonair quality environmental impacts of compliance, the remaining useful life of the source, existing pollution control technology at the source and the degree in improvement in visibility which may reasonably be anticipated to result from the use of a technology.

The Clean Air Act requires consideration of existing control technologies. When the Boardman Plant boiler was initially permitted, NTEC and DEQ evaluated the best available control technology available to the plant for controlling SO_2 emissions.[5] NTEC and DEQ concluded that this was the use of low sulfur coal—a practice that is still required by permit today. The boiler was accordingly designed to accommodate the unique firing characteristics of low sulfur coals. PGE is proposing that this existing control technique be relied upon in establishing BART by increasing the stringency of the SO_2 emission restriction from 1.2 lb/MMBtu to 0.96 lb/MMBtu and, ultimately, to 0.60 lb/MMBtu. This substantial (50 percent) decrease in allowable SO_2 emissions recognizes the existing control technique while ultimately decreasing the allowable sulfur content in the coal combusted in the Boardman Plant boiler. The proposed dates are the most expeditious dates by which the transition to reduced sulfur coal can be accomplished in light of the existing stock of coal at the plant (approximately 500,000 tons) and the current coal contracts in force through 2011. While semi-dry scrubbing might be

[5] Although the Boardman Plant predated the federal New Source Review (PSD) program, the structure of the impending program was known at the time of permitting and so the NTEC, working in association with DEQ, required the use of Best Available Control Technology (BACT) and required that PGE demonstrate through modeling that the Boardman Plant would not result in emissions impacts exceeding 10 percent of the ambient air quality standards.

appropriate for a coal-fired plant using higher sulfur coal, the addition of scrubbing is not appropriate for a plant prepared to expeditiously convert to reduced sulfur coal and that would only be operating for a limited period of time prior to closure.

The energy and nonair quality impacts of semi-dry scrubbing support the conclusion that the technology should not be required as a BART control. Semi-dry scrubbing has impacts that are more severe than those associated with the use of reduced sulfur coal alone. Semi-dry scrubbing requires additional fans, pumps and other electrical equipment that consume considerable energy, reducing the efficiency of the plant. In addition, the nonair quality environmental impacts, including water usage and waste disposal, are material. The best means of controlling SO_2 emissions is to not emit it in the first place. By converting from low sulfur coal to reduced sulfur coal, the Boardman Plant boiler is able to eliminate 50 percent of its allowable SO_2 emissions without creating additional energy or environmental impacts. When this control technique is combined with premature closure of the Boardman Plant boiler in 2020, there is no sound basis for requiring semi-dry scrubbing as a BART control technology.

The cost of compliance criterion similarly does not support requiring semi-dry scrubbing as a BART control in light of PGE's proposed reduced sulfur coal restriction/premature closure BART alternative. Semi-dry scrubbing would require a capital investment of approximately \$270 million and an operating cost of approximately \$13.9 million per year.[6] Since the SO_2 control equipment would only be operated for 6.5 years, cost effectiveness values for semi-dry scrubbing would be approximately \$5,600 per ton. Reducing the SO_2 permit limit by 50 percent imposes operational costs as well as additional risk because of the limited availability of coal mines that offer reduced sulfur coals and the substantial projected increase in demand. However, these operational costs, while material, are significantly lower than the capital and operational costs associated with semi-dry scrubbing. Due to the high capital costs for this technology, addition of semi-dry scrubbing would require an unreasonable investment in light of the short period that it would be operational.

Consideration of the remaining useful life of the Boardman Plant also supports the conclusion that DEQ should not require BART SO_2 emission limits more stringent than the 20 percent increasing to 50 percent reduction proposed by PGE based on the use of reduced sulfur coal. Section 169A of the Clean Air Act mandates that DEQ take into account the remaining useful life of the source as a criterion coequal with the other factors (e.g., visibility improvement). The EPA Guidelines suggest accounting for remaining useful life as a component of the cost of compliance. This has been done in

[6] In the Regional Haze Plan, DEQ already documented its conclusion that for multiple reasons wet scrubbing is not an appropriate BART technology for the Boardman Plant. That conclusion is not revisited here as nothing about the analysis has changed.

the assessment summarized above. However, Congress expressly identified the remaining useful life of the plant as a criterion distinct and separate from the cost of compliance criterion. The Department recognized in the Regional Haze Plan that it would not be appropriate to require costly scrubbers if the Boardman Plant boiler were required to cease operation prematurely. See, e.g., Regional Haze Plan at 155-156. This conclusion is even more compelling when the proposed 50 percent reduction in allowable SO_2 emissions is considered.

Improvement in visibility provides only minimal support for requiring post-combustion SO_2 controls when contrasted to the imposition of a reduced sulfur coal restriction and premature closure. Utilization of scrubbers would reduce the 98th percentile visibility impacts at Mt. Hood and Hells Canyon by a little over 1 deciview. Utilization of reduced sulfur coal such that emissions are limited to 0.60 lb/MMBtu will reduce the 98th percentile visibility impacts at Mt. Hood by 0.5 dv. The limited additional improvement in visibility resulting from the use of post-combustion controls (i.e. scrubbers) is insufficient to overcome the other impacts associated with post-combustion controls. Even this limited additional improvement associated with semi-dry scrubbers pales in comparison to the long term benefits associated with closure of the plant by the end of 2020. As noted, if SO_2 scrubbers were required, the time necessary to recover the cost would likely compel operation of the plant and the scrubbers for their full useful life. The marginal benefits of requiring semi-dry scrubbing as opposed to reduced sulfur coal are limited. When those limited benefits are compared to the long term benefit of closing the plant early and eliminating visibility impacts on all days after December 31, 2020, this factor weighs in favor of replacing the current BART SO_2 emissions limit with a limit based on reduced sulfur coal and closure no later than December 31, 2020.

Based on this analysis, scrubbers should not be considered as BART if PGE agrees to (1) limit SO_2 emissions to 0.96 lb/MMBtu (annual average) no later than December 31, 2011, (2) limit SO_2 emissions to 0.60 lb/MMBtu (annual average) commencing July 1, 2014, and (3) cease operation of the Boardman Plant boiler no later than December 31, 2020.

SO_2 Reasonable Progress Control Analysis

There is no basis for concluding that the SO_2 reduction technologies eliminated from consideration as BART controls would be appropriate as Reasonable Progress controls. For the reasons stated above, PGE believes that the factors specified in the Clean Air Act support the conclusion that semi-dry scrubbing should not be required as an SO_2 BART control if PGE will decrease the Boardman Plant boiler's allowable SO_2 emissions by 50 percent (20 percent by the end of 2011 and then by the full 50 percent by mid-2014) and the Boardman Plant boiler will not operate beyond December 31, 2020. There is nothing about the Reasonable Progress analysis that merits a different conclusion.

Particulate (PM) Control Selection

The Boardman Plant is already fitted with a cold-side ESP, which removes over 99 percent of PM from the flue gas. Considering the current baseline rate of 0.017 lb PM/MMBtu, none of the feasible control technologies were cost effective. Although a pulse jet fabric filter (PJFF), a COHPAC system, or a Wet ESP, in combination with the existing ESP, could achieve the PM emission limit of 0.012 lb/MMBtu currently reflected in the Regional Haze Plan, the cost effectiveness for these three technologies is $192,000, $187,000, and $350,000 per ton PM, respectively. These cost effectiveness values are unreasonably high. Therefore, none of these controls should be the basis for BART or Reasonable Progress PM limits more stringent than what is already required in the Boardman Plant permit. This conclusion is further supported if the requirement is added to the regulations that PGE cease operation of the Boardman Plant boiler no later than December 31, 2020.

1.0 Introduction and Objectives

The objective of this report is to provide the technical, regulatory and statutory basis for revisions to the regulations adopted as part of the Regional Haze Plan in light of changes in critical assumptions that have arisen since the Boardman Plant boiler was first assessed. When the Environmental Quality Commission (EQC) adopted the Regional Haze Plan in 2009, the Oregon Department of Environmental Quality (DEQ) stated that it would reevaluate and resubmit to the EQC its BART/Reasonable Progress conclusions if critical assumptions changed and PGE submitted a new BART/Reasonable Progress analysis. This document is in response to that agency commitment. This report documents the basis for requested changes to the BART regulations (OAR 340-223-0030) and Reasonable Progress regulations (OAR 340-223-0040) currently applicable to the Boardman Plant boiler.

1.1 Source Description and Background

The Boardman Plant is a 584 MW electric utility steam generating facility located near Boardman, Oregon, about 150 miles east of Portland. The Boardman Plant is jointly owned by PGE (65%), Idaho Power (10%), Power Resources Cooperative (10%) and BA Leasing BSC, LLC (15%). The Boardman Plant was issued its construction authorization from the Nuclear and Thermal Energy Council on February 27, 1975 and an Air Contaminant Discharge Permit from the DEQ on April 6, 1977. As part of the permitting process, PGE performed extensive modeling to demonstrate that the plant would operate in compliance with the ambient air quality standards. PGE also agreed to implement various controls to reduce air emissions, including the use of a cold-side ESP to reduce particulate emissions, the exclusive use of low sulfur coal to reduce SO_2 emissions, and the use of LNB and OFA to reduce NO_x emissions. These control technologies were considered Best Available Control Technology (BACT).

The Boardman Plant's steam generator consists of a subcritical, opposed wall-fired boiler that operates on balanced draft. The plant currently burns low sulfur Powder River Basin (PRB) coal. A summary of the operational characteristics are noted in Table 1-1. A detailed design basis of the Boardman Plant is included in Appendix A.

Table 1-1 Boardman Plant Operational Characteristics	
Item	**Unit 1**
Fuel Type	Subbituminous
Heating Value of Fuel, Btu/lb (HHV)	8,020 – 9,800
Unit Rating, MW (gross/net)	617 / 584
Net Plant Heat Rate, Btu/kWh	9,841
Boiler Heat Input, MMBtu/hr	5,793[7]
Type of Boiler/Manufacturer	Opposed-wall/Foster Wheeler
Steam Cycle	Subcritical
Draft of Boiler	Balanced
Existing Emissions Controls	
SO_2 (Pre-combustion Controls - Coal Type)	Low-sulfur coal
NO_x (Combustion Controls)	LNB, OFA (1st generation)
PM (Post-combustion Controls)	Cold-side ESP
While 5793 MMBtu/hr is considered the nominal boiler heat input, the maximum boiler heat input is roughly 6400 MMBtu/hr, based on an evaluation of CEMS data from 1997 to 2008 for the maximum 30-day average heat input value of the boiler.	

On July 6, 2005, the EPA issued its final *Regional Haze Regulations and Guidelines for Performing BART Determinations*. These rules/guidelines established a procedure for identifying those sources that must retrofit their existing facilities with BART and for determining what constitutes BART. The purpose of the BART program was to require controls, where appropriate, for facilities that were not subject to the new source review requirements of the 1977 Clean Air Act Amendments. Specifically, the BART rules apply exclusively to sources within one of the enumerated source categories and that were in existence prior to August 7, 1977.

Although the Boardman Plant did go through all the substantive new source review requirements of the 1977 Clean Air Act Amendments, DEQ still characterized the facility as subject to BART. Because the Boardman Plant is a steam electric plant of more than 250 MMBtu per hour heat input, it is in one of the BART eligible source categories.

[7] While 5793 MMBtu/hr is considered the nominal boiler heat input, the maximum boiler heat input is roughly 6400 MMBtu/hr, based on an evaluation of CEMS data from 1997 to 2008 for the maximum 30-day average heat input value of the boiler.

In order to be BART eligible, the plant would have to have been in existence, as that term is defined by EPA in the BART rules, before August 7, 1977. A plant is considered "in existence" if

> "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." 40 CFR 51.301

DEQ determined that the Boardman Plant had obtained all necessary preconstruction approvals or permits required by Federal, State, and local laws by April 6, 1977. Therefore, even though it had not yet begun normal operations in 1977, because the Boardman Plant was fully permitted and construction had commenced prior to August 7, 1977, the Boardman Plant was identified by DEQ as a BART source.[8]

On November 2, 2007, PGE submitted a BART analysis to DEQ evaluating the available NO_x, SO_2, and PM retrofit controls for the Boardman Plant. This analysis assumed that the Boardman Plant would operate for the rest of its physical life, i.e., until at least 2040. PGE noted that the analysis would require revision if it was determined that a shorter plant life was appropriate. On December 1, 2008, the Department published its proposed BART determination for the Boardman Plant. During the public comment period, PGE requested that DEQ consider allowing PGE to forego certain controls if the company committed to cease operation of the Boardman Plant boiler by dates certain.

On June 19, 2009, the EQC adopted the Regional Haze Plan. The Regional Haze Plan includes new regulations (OAR 340-223-0030) imposing NO_x, SO_2 and PM limitations reflective of BART and applicable to the Boardman Plant boiler. The NO_x 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 NO_x limits reflective of the "Reasonable

[8] For the same reasons that the Boardman Plant is considered a BART source, the plant was necessarily determined to have 1978 "actual emissions," as that term is defined in the Oregon Plant Site Emission Limit rules, equal to the plant's potential to emit.

Progress" requirements of Clean Air Act Section 169A. These requirements are summarized below in Table 1-2.

Table 1-2
Oregon Regional Haze Plan Requirements Applicable to the Boardman Plant Boiler

Limit (Assumed Control)	Installation Deadline	Authority
0.28 lb NO_x/MMBtu—30 day rolling average 0.23 lb NO_x/MMBtu—annual average (Low-NO_x 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 NO_x/MMBtu (SCR)	7/1/2017	Reasonable Progress

*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 NO_x limit changes to 0.23 lb/MMBtu as a 30 day rolling average.

In adopting the BART/Reasonable Progress requirements in the Regional Haze Plan, the EQC and DEQ acknowledged PGE's request for consideration of a boiler shutdown, but stated that early closure would need to be evaluated in response to 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 NO_x controls for the Boardman Plant "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." Regional Haze Plan at p. 155. 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." Regional Haze Plan at p. 202. Thus there was explicit recognition that PGE could petition DEQ for reconsideration of the BART and Reasonable Progress rules if external factors such as carbon regulation would result in early plant closure.

This revised BART/Reasonable Progress analysis was undertaken in response to DEQ's express commitment to consider a change to the BART and Reasonable Progress requirements. While specific legislation has not yet passed Congress, PGE believes that federal regulation of carbon from coal-fired power plants is likely and has therefore incorporated carbon costs in evaluating the future of the Boardman Plant in its Integrated Resource Plan (IRP) before the Oregon Public Utility Commission (OPUC). PGE's IRP analysis shows that the least-cost least-risk option for its customers is to operate the Boardman Plant boiler for its full lifetime if all of the BART and Reasonable Progress controls are installed. In response to requests from IRP stakeholders and OPUC staff, PGE has recently conducted additional analysis in the IRP that suggests that a better option for its customers, in terms of both cost and risk, could be to cease operations by the end of 2020; this option would require DEQ to revise the BART and Reasonable Progress regulations to delete the current OAR 340-223-0030(1)(b) and (1)(c) and OAR 340-223-0040(1). In their place, PGE proposes that DEQ impose a requirement that ultimately restricts the Boardman Plant boiler SO_2 emissions to 0.60 lb/MMBtu (half the current limit) and requires that the Boardman Plant boiler cease operation no later than December 31, 2020. PGE is submitting this revised BART/Reasonable Progress analysis to request that DEQ revise the Regional Haze Plan accordingly.

The methodology used for this BART and Reasonable Progress analysis follows closely that used in the November 2, 2007 submittal. The steps followed are summarized below.

1.2 BART/Reasonable Progress Analysis Methodology

In its BART Guidelines, EPA outlined an engineering, economic, and visibility modeling analysis to identify the best method of retrofit emission reduction for pollutants that cause visibility impacts in federal Class I areas (NO_x, SO_2, and PM). To identify the best method of emission reduction, data are collected through a five step process to arrive at a selection of the best methods of emissions reduction of NO_x, SO_2, and PM at the BART source. The five steps followed to develop information for making the BART determination are the following:

1. Identify all available retrofit control technologies.
2. Eliminate technically infeasible options.
3. Evaluate control effectiveness of remaining control technologies.
4. Evaluate impacts and document the results.
5. Evaluate visibility impacts.

These steps generate data that are used to evaluate the costs and benefits of various control technologies and, ultimately, identify the retrofit technology appropriate for installation at the source. The first four of these steps are shared by the Reasonable Progress analysis; the Clean Air Act does not identify visibility impacts as an evaluative criterion for identifying Reasonable Progress controls. The Clean Air Act identifies an additional step, evaluation of the time necessary for compliance, that is not identified for BART. Each of these steps is further explained in the following subsections.

1.2.1 Identify All Available Retrofit Control Technologies (Step 1)

The first step of the BART/Reasonable Progress analysis is to identify all available retrofit control technologies. A control technology is considered as an available retrofit if it has practical potential for application to the BART-eligible source. The technology considered can be a method, system, or a combination of both options for control of a pollutant. Technologies that have been successfully applied to similar sources with similar gas stream characteristics are considered available. However, technologies that have not been applied to full scale operations are not considered available. Since the Boardman Plant boiler is equipped with existing control technologies, the control options evaluated included improvements or optimization of the existing control technologies. Section 3.0 addresses the requirements of Step 1 of the BART/Reasonable Progress analysis.

1.2.2 Eliminate Technically Infeasible Options (Step 2)

Step 2 of the BART/Reasonable Progress analysis involves the evaluation of all the identified available retrofit control technologies to determine technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source or if there is technical agreement that the technology can be applied to the source. Two terms, available and applicable, are used to define the technical feasibility of a control technology. A technology that is being offered commercially by vendors or is in commercial demonstration or licensing is deemed an available technology. Technologies that are in development and testing stages are classified as not available. A commercially available technology is applicable if it has been previously installed and operated at a similar type of source, or a source with similar gas stream characteristics. Section 4.0 addresses the requirements of Step 2 of the BART/Reasonable Progress analysis.

1.2.3 Evaluate Control Effectiveness of Remaining Control Technologies (Step 3)

Once all the technically feasible control technology alternatives are identified in Step 2, the control effectiveness of each control technology is evaluated in Step 3, and the technologies are ranked. The control effectiveness is documented for each technology and expressed both in terms of tons per year of post-control emissions and pounds of emissions per MMBtu heat input. Data for the control effectiveness of a technology were obtained by considering regulatory decisions or evaluations that have been performed on the effectiveness of the technology. Other reference sources for control effectiveness data are technology performance data provided by manufacturers (usually in the form of performance guarantees), engineering estimates, and demonstrated effectiveness of the technology at existing operating sources. The most stringent level of control demonstrated for each technology was used for its control effectiveness. For purposes of comparison, the technologies were ranked in order of effectiveness, from the current controls to the most effective control. Section 5.0 describes the evaluations performed for Step 3 of the BART/Reasonable Progress analysis.

1.2.4 Evaluate Impacts and Document the Results (Step 4)

Once the control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed in Step 4. The impacts of utilizing the control technology at the Boardman Plant are evaluated. The evaluation of the impacts (impact analyses) is included in Section 6.0. The impact analyses performed are:

- Costs of compliance.
- Energy impacts.
- Nonair quality environmental impacts.
- Existing pollution control technology (BART only).
- Time necessary for compliance (Reasonable Progress only).
- Remaining useful life.

The first impact analysis evaluates the costs of compliance. This analysis is performed to indicate the cost to install and operate the control technology. The capital and operating annual costs are estimated based on established design parameters, and then the annualized cost is determined. The annualized cost ($/year) is then divided by the estimated quantity of pollutant removed (tons/year) to determine the cost-effectiveness ($/tons) of each control technology. Establishing cost-effectiveness allows the evaluation of different control technologies on an economic basis for potential elimination from further consideration. Consistent with the EPA's directive, two types of cost-effectiveness are considered in this BART/Reasonable Progress analysis: average and incremental cost-effectiveness. The average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option. It has a unit of $/incremental ton removed. The incremental cost-effectiveness is a good measure when comparing technologies that have similar removal efficiencies. Consistent with

EPA guidance issued in relation to Best Available Control Technology determinations, cost of compliance is not necessarily evaluated for technologies that are considered acceptable to PGE.

The second impact analysis evaluates the energy impacts of a particular control technology. The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. Examples of direct energy impacts include the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance (pressure loss) of the control technology in the flue gas flow path. The cost of these energy impacts includes additional fuel cost and/or the cost of lost generation that would need to be purchased from another source because of implementation of the technology.

The third impact analysis evaluates the nonair quality environmental impacts. Nonair quality environmental impacts are evaluated to determine whether a particular control technology has any environmental impacts not related to air quality – either positive or negative. An example of a negative nonair quality environmental impact is the generation of wastewater discharge and solid waste.

The fourth impact analysis evaluates the existing pollution control technology. This particular factor is identified by the Clean Air Act only in relation to the BART analysis. However, the Reasonable Progress analysis is conducted to determine what control technologies would be required beyond those resulting from the BART analysis. Therefore, the Reasonable Progress analysis starts from a baseline of what is required by BART.

The fifth impact analysis evaluates the time necessary for compliance. This particular factor is identified by the Clean Air Act only in relation to the Reasonable Progress analysis. However, this factor is considered in the BART analysis in relation to what constitutes the "expeditiously as possible" deadline for implementation of the control technology imposed by BART.

The sixth impact analysis required by the Clean Air Act to be considered is the remaining useful life of the source subject to BART. In the preliminary analysis, useful life is typically considered in relation to the effect on the annualized costs of the retrofit controls for capital recovery. This occurs when the source has a shorter remaining useful life than the expected service life of the control technology. This would require expedited capital recovery, thus affecting the cost-effectiveness of the control technology, particularly for technologies that require a large capital expenditure. However, the Clean Air Act does not limit consideration of remaining useful life to the economic analysis. Congress' choice to include remaining useful life as a factor independent of economic impacts evidences a Congressional intent that remaining useful life be more than just a component of the economic impacts analysis.

1.2.5 Evaluate Visibility Impacts (Step 5)

Potential visibility improvement from the addition of each control technology is determined from modeling results using the CALPUFF dispersion modeling system. A modeling protocol was previously developed in consultation with, and approval of, DEQ. This protocol was also followed in this revised analysis. Items that were considered in the modeling protocol include the following:

- Meteorological and terrain data.
- Stack height, temperature, exit velocity, and elevation.
- Pre- and post-control emission rates.
- Receptor data from appropriate Class 1 areas.

After completing model runs at pre- and post-control emission rates, a determination of the visibility improvement was made. The visibility improvement was determined by comparing the 98th percentile days at pre- and post-control emission rates.

Consideration of the degree of improvement in visibility is a factor specified by the Clean Air Act only in relation to the determination of what constitutes BART. Visibility impacts are not identified as a decision criterion for Reasonable Progress. However, as the purpose of Reasonable Progress is to achieve the reasonable progress goals outlined in the Regional Haze Plan, the goal of reducing visibility impacts is a consideration, if not an evaluative criterion, in the Reasonable Progress analysis.

1.2.6 Selecting the Best Alternative

From the analyses performed in the five steps described above, tables were prepared assessing the merits and demerits of the control technology options, with the focus on the top-ranked technologies. These factors were then evaluated to select the best alternative. PGE strove to maintain the existing regulatory limits and determinations where possible so as to minimize disruption to the regulations previously adopted by the EQC.

1.3 Reasonable Progress Analysis Methodology

Reasonable Progress is an engineering and economic analysis similar, but not identical, to the BART analysis, to identify secondary levels of emission reduction for pollutants that cause visibility impacts in federal Class I areas (NO_x, SO_2, and PM). EPA has issued no regulatory guidance on how to perform Reasonable Progress analyses and so the Clean Air Act itself is the sole basis for determining the appropriate means of establishing Reasonable Progress limits.[9] As noted above, the Reasonable Progress analytical criteria stated in the Clean Air Act differ from those for BART. Specifically, Reasonable Progress includes a criterion, "the time necessary for compliance," that is not present in the BART criteria. In addition, Reasonable Progress lacks the requirement to evaluate "the degree of improvement in visibility," which is present in the BART analytical process. Furthermore, while BART includes consideration of existing controls as an evaluative criterion, EPA explained that Reasonable Progress is determined using a baseline condition reflecting the visibility improvements expected to result from implementation of other Clean Air Act requirements—including BART. 40 CFR 51.308(d)(3)(v). Both BART and Reasonable Progress require consideration of the cost of compliance, the energy and nonair quality environmental impacts of compliance and the remaining useful life of the source. In evaluating and suggesting revisions to the Reasonable Progress NO_X limits in OAR 340-223-0040, PGE has followed the process outlined above in relation to BART, while respecting the differences required by the Clean Air Act when determining Reasonable Progress limits.

[9] EPA issued guidance for the setting of Reasonable Progress goals. *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program* (June 1, 2007). This guidance notes that Reasonable Progress determinations may not be necessary in the first planning period. It also notes that states need not reassess Reasonable Progress for sources that have already undergone BART. However, while there is cursory mention in the guidance document of the Reasonable Progress evaluation factors mandated by the Clean Air Act, EPA introduces the document saying that it "is to provide guidance to States in setting reasonable progress goals…" The purpose of the document was not to identify a comprehensive process for establishing Reasonable Progress goals.

2.0 Basis of Analysis

2.1 Design Basis

A detailed design basis was established for the Boardman Plant. The information in the design basis was used for equipment sizing, performance calculations, cost estimates (capital, operating, and maintenance), and estimating resources consumption, auxiliary power requirements, and byproduct disposal. The complete design basis is shown in Appendix A. The design basis with the original design coal case was used as the basis for this BART/Reasonable Progress analysis. The design basis was also established for two other coal cases: typical (Buckskin Mine) and maximum (Black Butte Mine). Performance calculations were based on the design basis coal.

2.2 Economic Data

2.2.1 Capital Cost Estimates

Capital cost estimates were developed for retrofit control technologies that were identified as technically feasible for the Boardman Plant. The capital cost estimates were based on the Coal Utility Environmental Cost (CUECost) generated estimates, cost data supplied by equipment vendors (budget estimates), and estimates from in-house design/build projects. The capital cost estimates include direct and indirect costs and are stated in 2010 dollars. The cost estimates are consistent in format with the guidance from the EPA's *Office of Air Quality Planning and Standards Cost Manual*. The capital cost accuracy is expected to be +/- 30 percent. The costs presented in this report are preliminary and should only be used for comparative purposes in this BART/Reasonable Progress analysis. The capital cost estimates will be refined throughout the upcoming preliminary engineering phase until actual equipment and construction contracts are procured.

Direct costs consist of purchased equipment, installation, and miscellaneous costs. The purchased equipment costs are the costs for purchasing the control technology equipment from equipment vendors (including freight). An itemized list of major components of the direct capital cost is included for each feasible control technology in Appendix D. The installation costs include construction costs for installing the new controls and also take into account the retrofit difficulty that can be expected from the existing site configuration and the installation requirements of the controls. Finally, miscellaneous costs include the costs for additional items such as site preparation, buildings, and other site structures needed to support the controls. The direct cost estimates were based on the following assumptions:

- Regulatory permitting has been completed.

- Ample supply of craft labor and construction equipment is available.
- Normal lead-times for equipment deliveries are expected.

Indirect costs are costs that are not related to the equipment purchased but are associated with any engineering project, such as the retrofit of an air quality control technology. Indirect costs considered in this evaluation include the following:

- Contingency.
- Engineering.
- Owner Costs.
- Construction management.
- Startup and spare parts.
- Performance Tests.

2.2.1.1 Contingency. Contingency accounts for unpredictable events and costs that could not be anticipated during the normal cost development of a project. Costs assumed to be included in the contingency cost category are items such as possible redesign and equipment modifications, unforeseen weather-related delays, strikes and labor shortages, escalation increases in equipment costs, increases in labor costs, delays encountered in startup, etc.

2.2.1.2 Engineering. Engineering costs include any services provided by an architect/engineer or other consultant for support, design, and procurement of the air quality control project.

2.2.1.3 Owner Costs. Table 2-1 lists possible owner costs. Some of the costs are not applicable to all of the evaluated technologies but are representative of the typical expenditures that the owner(s) will experience through an air quality control retrofit project.

2.2.1.4 Construction Management. Construction management includes costs for field management staff, such as supporting staff personnel, field contract administration, field inspection and quality assurance, project controls, technical direction, and startup management. It also includes cleanup expenses for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, other required labor-related insurance, performance bond, and liability insurance for equipment and tools.

2.2.1.5 Startup and Spare Parts. Startup services include the costs for management of the startup planning and procedure and training of personnel for the commissioning of the newly installed control technology. Also included are the general low-cost spare parts required for each control technology system. High-cost critical spare parts are not included in this analysis; they are determined on a case-by-case basis from manufacturer recommendations and owner requirements.

Table 2-1
Typical Owner Costs

<table>
<tr><td>Project Development:
Legal assistance
Permitting compliance
Public relations/community development
Road modifications/upgrades</td><td rowspan="2">Plant Startup/Construction Support:
Owner’s site mobilization
O&M staff training
Initial test fluids and lubricants
Initial inventory of chemicals/reagents
Consumables
Construction all-risk insurance
Startup/construction auxiliary power purchase</td></tr>
<tr><td>Financing:
Debt service reserve fund
Financial analysis</td></tr>
<tr><td>Owner’s Project Management:
Project management
Engineering due diligence
Preparation of bid documents and selection of contractors and suppliers</td><td>Taxes/Advisory Fees/Legal:
Taxes
Market and environmental consultants
Owner’s legal expenses:
Interconnect agreements
Contract-procurement and construction
Property transfer</td></tr>
</table>

2.2.1.6 Cost Escalations. No contingency has been devoted to cost escalations over those of inflation. It is noted that a large number of coal plants will be built, or undertake emissions controls retrofits during this period. This is expected to intensify competition for equipment, basic materials, craft labor and engineering talent.

2.2.1.7 Performance Tests. Performance tests are conducted after installation of the control technologies to validate the performance of the emissions reduction systems. Typical performance tests are flue gas emissions testing that may be performed at various points of the flue gas flow path. The results of the performance tests are used to ensure compliance with performance guarantees and emissions limits.

2.2.2 Annual Operating and Maintenance Cost Estimate

Annual operating and maintenance (O&M) costs typically consist of the following cost categories:

- Reagent costs.
- Electric power costs.

- Makeup water costs.
- Wastewater treatment and byproduct disposal costs.
- Operating labor costs.
- Maintenance materials and labor costs.

The costs of reagent, electric power, makeup water, wastewater, and byproduct disposal are variable annual costs that are dependent on the specific control technology. Operating and maintenance materials and labor are fixed annual costs that do not vary with these factors. Table 2-2 lists the major economic factors used to estimate annual O&M costs.

2.2.2.1 Reagent Costs. Reagent costs include the costs for the material and delivery of the reagent to the facility as well as for reagent preparation. Reagent costs are a function of the quantity of the reagent used and the market price of the reagent. The quantity of reagent used will vary with the quantity of pollutant that must be removed as well as the reagent utilization ratio. Reagent costs were defined for the following reagents:

- Limestone.
- Lime.
- Anhydrous ammonia.
- Urea.
- Magnesium hydroxide ($Mg(OH)_2$) for wet ESP (WESP) applications.

2.2.2.2 Electric Power Costs. Additional auxiliary power will be required to run some of the control technology systems evaluated for the Boardman Plant. The power requirements of each system vary depending on the type of technology and the complexity of the system. Electric power costs include increases in induced draft (ID) fan power consumption caused by the flue gas pressure losses through the new equipment.

2.2.2.3 Makeup and Service Water Costs. Makeup water or service water is required for some of the control technology systems evaluated for the Boardman Plant. Examples of water consumption in control technologies include water to support reagent preparation for limestone-forced oxidation or lime-based scrubbers, ammonia solution preparation from urea for SCR and selective noncatalytic reduction (SNCR) processes and for electrode plate washing in a WESP. Additional costs might be incurred for water treatment to obtain the required water quality. For the cost estimations, two types of water quality were considered: makeup and service water. Depending on the process, the appropriate water type was included in this cost category.

Table 2-2 Economic Evaluation Factors	
Economic Factor	**Value**
Reagent Cost	
Lime	\$132/ton
Limestone	\$46/ton
Ammonia (anhydrous)	\$450/ton
Urea	\$315/ton
$Mg(OH)_2$	\$1.20/ton
SCR Catalyst Cost	\$6,000/m^3
Makeup Water Cost	\$2/1,000 gal
Service Water Cost	\$0.50/1,000 gal
Wastewater Treatment Cost	\$0.50/1,000 gal
Byproduct Disposal Cost	\$10/ton
Electric Power Cost	\$50/MWh
Steam Cost	\$3.50/1,000 lbs
Maintenance Cost	3% of cap cost/yr
Control Technology Economic Life	From control equipment startup date to plant shutdown date
Interest Rate	7%
Present Worth Discount	9.2%
Capital and O&M Escalation Factor	3%
Start-up Date for all Combustion NO_x Control Systems	July 1, 2011
Start-up Date for all SO_2 or PM Control Systems	July 1, 2014
Start-up Date for SCR NO_x Control System	July 1, 2016
Start-up Date for SNCR NO_x Control System	July 1, 2014
Boiler Shut-Down Date (no later than)	December 31, 2020
Capital Recovery Factor for all Combustion NO_x Control Systems	14.76
Capital Recovery Factor for all SO_2 or PM Controls	19.67
Capital Recovery Factor for SNCR Control System	19.67
Capital Recovery Factor for SCR Control System	26.67
Allowance for Funds During Construction (AFDC)	8.99%
Fully Loaded Operating Labor Cost, per person	\$100,000/year

2.2.2.4 Wastewater and Byproduct Disposal Costs. Some control technologies generate wastewater and/or byproduct that will require treatment and/or disposal. For example, a wet FGD system generates a blowdown wastewater stream to regulate the level of chlorides in the slurry recirculation system. Also, a wet FGD system forms calcium sulfate and calcium sulfite byproducts when the limestone reacts with SO_2. For wastewater treatment and byproduct disposal cost, the following key assumptions were utilized:

- Sales of fly ash captured in the existing ESP is unaffected by retrofit technologies downstream of the existing ESP.
- All collected byproducts (excluding existing ESP fly ash) are landfilled.
- All wet scrubber equipment effluent requires wastewater treatment prior to being discharged to the environment.
- Ammonia-based NO_x reduction systems may affect the salability of fly ash. However, for this analysis, the impacts were assumed to be minimal.

2.2.2.5 Operating Labor Costs. Operating labor costs are developed by estimating the number and type of employees that will be required to run the new control equipment. These estimates are based on industry common practices. The labor costs are based on a fully loaded labor rate and a 40 hour per week work schedule.

Typically, a complex emissions control technology will require a combination of the following personnel:

- Supervisor
- Control room operator.
- Roving operator.
- Relief operator.
- Laboratory technicians.
- Equipment operators.
- Maintenance technicians.

In the evaluation of direct annual costs for each control technology in Appendix D, the estimated full-time-equivalent operating labor required is identified.

2.2.2.6 Maintenance Materials and Labor Costs. The annual maintenance materials and labor costs are estimated as a percentage of the total equipment costs of the system. On the basis of typical utility industry experience, maintenance materials are estimated to be between 1 and 5 percent of the total direct capital costs, depending on the retrofit technology. For technologies that replace a similar existing technology at the plant site, a determination of the additional maintenance requirements was performed. If the required maintenance materials and labor are similar to the existing technology, no additional maintenance costs are included for the new control technology.

2.3 Baseline Emissions

For this revised BART analysis, the baseline emissions for NO_x, SO_2, and PM were established for the comparisons of the various control technology options. The baseline emissions established for the Boardman Plant for purposes other than visibility assessment are summarized in Table 2-3. The emission rates represent the highest rolling 12 month total between 2003 and 2005. Consistent with EPA's BART Guidelines, the baseline emission rate used for modeling purposes reflects the highest 24-hour average actual emission rate.

Table 2-3
Baseline Emissions

Pollutant	Emissions		Data Source
NO_x	0.43	lb/MMBtu	2003-2005 CEMS Data
	10,349	ton/yr	2003-2005 CEMS Data
SO_2	0.614	lb/MMBtu	2003-2005 CEMS Data
	14,902	ton/yr	2003-2005 CEMS Data
PM	0.017	lb/MMBtu	2003-2005 CEMS Data
	417	ton/yr	2003-2005 CEMS Data

For purposes of the Reasonable Progress analysis, EPA directed in Section 4.1 of its *Guidance for Setting Reasonable Progress Goals* that Reasonable Progress was to build upon the emission reductions resulting from other programs, including BART. Therefore, the Reasonable Progress analysis used compliance with the recommended BART requirements as the baseline emission rate.

2.4 Project Assumptions

In performing the BART/Reasonable Progress analysis, several general assumptions were made to facilitate the conceptual design of the technically feasible control technologies. The following are key project assumptions:

- Plant availability will potentially be affected by the installation of new control equipment. However, any changes in plant availability are assumed to be insignificant in this analysis.
- The site will have sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down and staging.

- Any repairs, rehabilitation, and/or ductwork stiffening of the existing boiler and ductwork equipment are assumed to be minor and are included in contingency costs.
- Byproducts produced from the emissions reduction processes will be disposed at the available landfill area on-site.
- When not contaminated with scrubber products, fly ash captured by PM control technologies is sold.
- When the scrubber byproducts contaminate the fly ash, such as in the case of the semi-dry FGD, disposal costs are included.
- Design and installation of post-combustion controls will not begin unless and until the OPUC acknowledges PGE's investment in the controls as part of an Integrated Resource Plan.

2.5 Modeling Baseline Conditions

Stack outlet conditions for all the technically feasible control technologies were calculated and are presented in Appendix B. The outlet conditions were calculated according to the design basis data, technology control effectiveness, and design parameters. The types of stack outlet data included are the following:

- Flue gas flow rate.
- Flue gas velocity.
- Flue gas temperature.
- Flue gas pressure.
- SO_2 emissions rate.
- NO_x emissions rate.
- PM emissions rate.

3.0 Identification of All Available Retrofit Emission Control Technologies (Step 1)

In Step 1 of the BART/Reasonable Progress analysis, all available retrofit control technologies that have a practical potential for application at the Boardman Plant were identified. These technologies were considered as available technologies. The control technology may be a method, system, or combination of reduction technologies for control of a pollutant. Sections 3.1 through 3.3 describe the control technologies for the three pollutants: NO_x, SO_2 and PM. Information on the working principle, retrofit considerations, and advantages and disadvantages of each technology is also provided.

3.1 NO_x Control Technologies

The following NO_x control technologies were identified as available for retrofit at the Boardman Plant and are summarized in Subsections 3.1.1 through 3.1.15:

- SCR.
- SNCR.
- SNCR/SCR hybrid (Cascade).
- ECOTUBE.
- LoTOx.
- Natural gas reburn.

3.1.1 Selective Catalytic Reduction

SCR systems are widely used for achieving post-combustion reductions in NO_x emissions. In SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions when passed over an appropriate amount of catalyst. The NO_x and ammonia reagent react to form nitrogen and water vapor. The reaction mechanisms are very efficient, with a reagent stoichiometry of approximately 1.05 (on a NO_x reduction basis) and with low ammonia slip (unreacted ammonia). A simplified schematic diagram of a typical SCR reactor utilizing aqueous ammonia injection is illustrated on Figure 3-1.

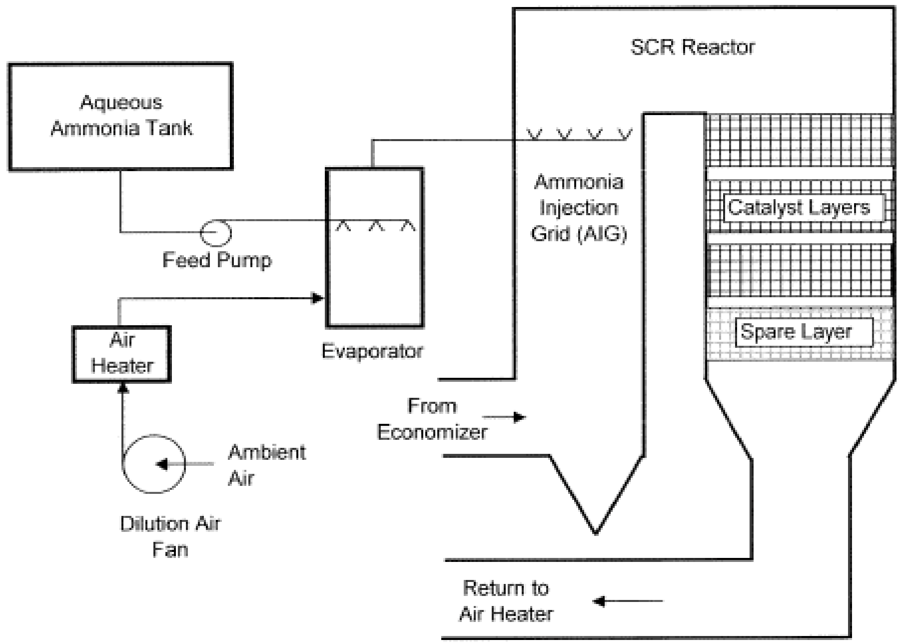

Figure 3-1
Schematic Diagram of a Typical SCR Reactor

The SCR reactor is the housing for the catalyst. The reactor is basically a widened section of ductwork modified by the addition of gas flow distribution devices, catalyst, catalyst support structures, access doors, and sonic horns/soot blowers. An ammonia injection grid is located upstream of the SCR reactor. The SCR reactor is typically elevated above and upstream of the air heater and particulate emissions control equipment (typically an ESP). Gas flow direction through the reactor is vertically downward for coal fired applications. In a "high-dust" SCR arrangement, the reactor is located between the outlet of the economizer and the inlet of the air heater. The high-dust system is typically the most economical and preferred arrangement where physically possible.

From a design standpoint, the SCR ammonia-catalytic reaction requires a temperature range of 600-750º F to be effective. As such, the SCR must be located after the convective pass of the boiler but before the air preheater. For the Boardman Plant, the temperature of the hot combustion gases exiting the boiler before entry to the air preheater is well in excess of 800º F. The Boardman Plant boiler was not designed with space in the ductwork or with an appropriate temperature profile for a future SCR. Very challenging and complex modifications to the boiler will be required to lower the gas path temperature to the desired range while still maintaining the air temperature exiting the air preheater to the pulverizer in order to properly dry the coal and maintain combustion efficiency. The costs of such modifications are expected to be substantial, up to approximately $45 million dollars.

The oxidation of SO_2 to SO_3 could also require moderate air heater modifications since the acid dew point temperature of the flue gas is directly related to SO_3 concentration. As the SO_3 concentration increases, the acid dew point of the flue gas increases, potentially increasing corrosion in downstream equipment or possibly requiring an increase in the air heater gas outlet temperature.

The ammonia reagent for the SCR systems can be supplied by anhydrous ammonia, aqueous ammonia, or by conversion of urea to ammonia. Since the ammonia is vaporized prior to contact with the catalyst, the selection of ammonia type does not influence the catalyst performance. However, the selection of ammonia type does affect other subsystem components, including reagent storage, vaporization, injection control, and balance-of-plant requirements. The vast majority of worldwide installations use anhydrous ammonia.

SCR systems have a variety of interfacing system requirements to support operations. These requirements predominantly relate to draft, auxiliary power, soot blowing steam, gas temperature, controls, ductwork, reactor footprint, and air heater. The SCR system will affect the boiler draft system. Depending on arrangement and performance requirements, draft losses can range from 4 to 10 in. wg, requiring the addition of ID booster fans. If necessary, ductwork and/or boiler box reinforcement may also be required. Auxiliary power modifications may also be necessary for the fan modifications and for ammonia supply system requirements.

The major impact of the SCR system can be seen at the air heater, where there are two areas of concern. One concern is the formation and deposition of ammonium bisulfate on the air heater surface. This will cause an increase in the pressure drop of the air heater, degrade its performance, and decrease plant efficiency. The other potential danger for the air heater is high concentrations of SO_3 in the flue gas. If the acid dew point temperature has been increased to more than the exhaust temperature, a significant amount of acid gases will condense in the air heater and lead to pluggage and corrosion. Several measures can be taken to avoid or correct this situation. Most important is the right composition of the catalyst to minimize the SO_2 to SO_3 conversion rate.

The effectiveness of the SCR system in a high-dust application is limited by ash fouling of the catalyst. Continuous heavy soot blower cleaning is required, which results in temperature cycles in the air heater and boiler. It can also erode the catalyst. The activity of the catalyst degrades over time even with cleaning. As the catalyst becomes deactivated, more ammonia must be injected to maintain NO_x reduction levels. This results in an increased amount of ammonia slip and ammonia bisulfate fouling of the air heaters.

For many units, the use of NLNB/MOFA along with SCR has been utilized. It should be noted that in the case of a new unit, the SCR can be designed for optimum performance with long residence times. The economizer outlet duct can also be designed for an optimum SCR arrangement. On an existing unit however, the ability to install an "optimum" arrangement for an SCR is limited by the existing plant and unit specific conditions and restrictions. SCR, as stated previously, is located between the economizer and the air heater for a high dust arrangement. This is typically a very congested area of the plant. Plant equipment (such as fans, boiler support steel, and underground utilities) restrict the possible ductwork arrangements as well as increase the complexity of the retrofit. SCR performance is highly dependent on having even flow distribution into the ammonia injection grid and the catalyst.

3.1.2 Selective Noncatalytic Reduction

SNCR systems reduce NO_x emissions by injecting a reagent at multiple levels in the boiler, as illustrated on Figure 3-2. SNCR systems rely solely on reagent injection, rather than a catalyst, and an appropriate reagent injection temperature, good reagent/gas mixing, and adequate reaction time to achieve NO_x reductions. SNCR systems can use either ammonia or urea as the reagent. Ammonia or urea is injected into areas of the steam generator where the flue gas temperature ranges from 1,500 to 2,200° F. The furnace of a pulverized coal fired boiler operates at temperatures between 2,500 to 3,000° F.

SNCR systems are capable of achieving a NO_x emissions reduction as high as 50 to 60 percent in optimum conditions (adequate reaction time, temperature, and reagent/ flue gas mixing, high baseline NO_x conditions, multiple levels of injectors) with ammonia slips of 10 to 50 ppmvd. Lower ammonia slip values can be achieved with lower NO_x reduction capabilities. Typically, optimum conditions are difficult to achieve, resulting in emissions reduction levels of 15 to 25 percent for retrofit applications. Potential performance is very site-specific and varies with fuel type, steam generator size, allowable ammonia slip, furnace CO concentrations, and steam generator heat transfer characteristics.

SNCR systems reduce NO_x emissions using the same reduction mechanism as SCR systems. Most of the undesirable chemical reactions occur when reagent is injected at temperatures above or below the optimum range. At best, these undesired reactions consume reagent with no reduction in NO_x emissions, while, at worst, the oxidation of ammonia can actually generate NO_x. Accordingly, NO_x reductions and overall reaction stoichiometry are very sensitive to the temperature of the flue gas at the reagent injection point. This complicates the application of SNCRs for boilers larger than 100 MW.

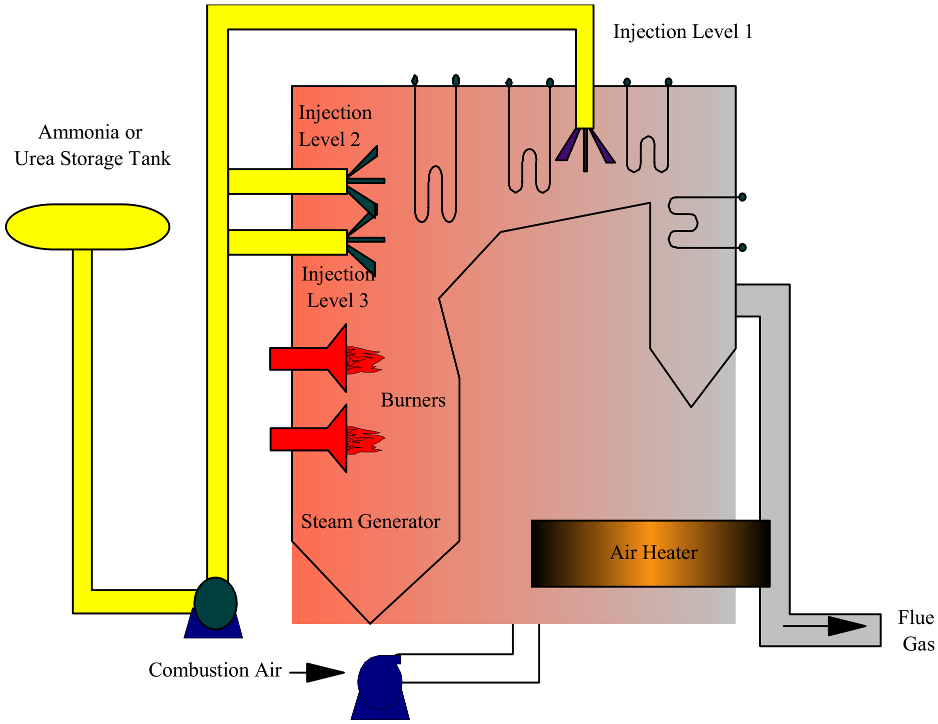

Figure 3-2
Schematic of SNCR System with Multiple Injection Levels

The NO_x reduction potential of SNCR systems is limited by boiler geometry and temperature profiles (which vary as a function of load) that affect reagent and flue gas mixing. For large boilers, the design challenge is to achieve appropriate residence times (in excess of 1 second) in the optimum temperature range (1500 to 2200^{o} F). For an existing boiler, waterwall and steam piping modifications would be necessary to accommodate the installation of SNCR reagent injectors. Multiple levels of steam-cooled reagent injectors or lances would be required. For existing boilers, the convection pass is very congested for optimum SNCR system operation. Without extensive modifications, this could lead to limited NO_x reduction capabilities. SNCR systems also tend to have higher ammonia slip, which fouls air heater surfaces.

3.1.3 SNCR/SCR Hybrid

The SNCR/SCR hybrid system uses components and operating characteristics of both SNCR and SCR systems. Hybrid systems were developed to combine the low capital cost and high ammonia slip associated with SNCR systems with the high reduction potential and decreased ammonia slip inherent in the catalyst of SCR systems. The result is a NO_x reduction alternative that can meet initially low NO_x reduction requirements but can be upgraded to meet higher reductions at a future date, if required.

The SNCR component of the hybrid system is identical to the SNCR system described previously, except that the hybrid system may have more levels of multiple lance nozzles for reagent injection. This will increase the capital cost of the SNCR component of the hybrid system. During operation, the SNCR system would be allowed to inject higher amounts of reagent into the flue gas. This increased reagent flow has a twofold effect: NO_x reduction within the boiler is increased while ammonia slip also increases. The ammonia that slips from the SNCR is then used as the reagent for the catalyst.

There are two design philosophies for using this excess ammonia slip. The most conservative hybrid systems use the catalyst simply as an ammonia slip "scrubber" with some additional NO_x reduction. As with in-duct systems, the flue gas velocity through the catalyst is an important factor in design. Operating in this mode allows maximum NO_x reduction within the boiler by the SNCR, while minimizing the catalyst volume requirement. While some NO_x reduction is realized at the catalyst, the relatively small catalyst requirement of this design can potentially allow the retrofit of all the catalyst in a true in-duct arrangement with no significant ductwork changes, arrangement interference, or structural modifications. The second philosophy uses adequate catalyst volume to obtain significant levels of additional NO_x reduction. The additional reduction is a function of the quantity of ammonia slip, catalyst volume, and distribution of ammonia to NO_x within the flue gas. Using ammonia slip produced by the SNCR system is not a high efficiency method of introducing reagent, because of the low reagent utilization discussed as a part of the SNCR. Therefore, even though the reaction at the catalyst requires 1 ppm of ammonia to remove 1 ppm of NO_x, the SNCR must inject at least 3 ppm of ammonia to generate 1 ppm of ammonia at the catalyst.

Catalyst volume is strongly influenced by the NO_x reduction required and the ammonia distribution. The impact of catalyst volume on the design of a hybrid system is on the size of the reactor required to hold the catalyst. If multiple levels of catalyst operating at low flue gas velocity are required, some modifications will be required to the existing ductwork. If widening the ductwork cannot provide adequate catalyst volume, then a separate reactor is required, which quickly reduces the capital cost advantage of a hybrid system.

As described in Subsection 3.1.7, the SCR catalyst reaction occurs within the temperature range of 600 to 750° F. As such, the catalyst must be located after the convective pass of the boiler but before the air preheater. For the Boardman Plant, the temperature of the hot combustion gases exiting the boiler before entry to the air preheater is well in excess of 800º F. The Boardman Plant boiler was not designed with space in the ductwork or with an appropriate temperature profile for a future SCR. Very challenging and complex modifications to the boiler will be required to lower the gas path temperature to the desired range while still maintaining the air temperature exiting the air preheater to the pulverizer in order to properly dry the coal and maintain combustion efficiency. The costs of such modifications are expected to be substantial, negating the capital cost advantage of a hybrid system.

3.1.4 ECOTUBE

The ECOTUBE system utilizes retractable lance tubes that penetrate the boiler above the primary burner zone and inject high-velocity air as well as reagents. The lance tubes work to create turbulent airflow and to increase the residence time for the air/fuel mixture. In principle, the OFA and SNCR processes are combined in this technology.

ECOTUBE is capable of reducing NO_x, while improving thermal efficiency, by optimizing the combustion process in boilers. An illustration of the ECOTUBE installation in a typical boiler is shown on Figure 3-3.

The water-cooled ECOTUBEs are automatically retracted from the boiler on a regular basis and cleaned to remove layers of soot and other deposits. Additional benefits have been identified by the supplier in terms of furnace combustion improvements that increase efficiency, reduce fuel usage, and reduce corrosion and erosion in the boiler and backend equipment.

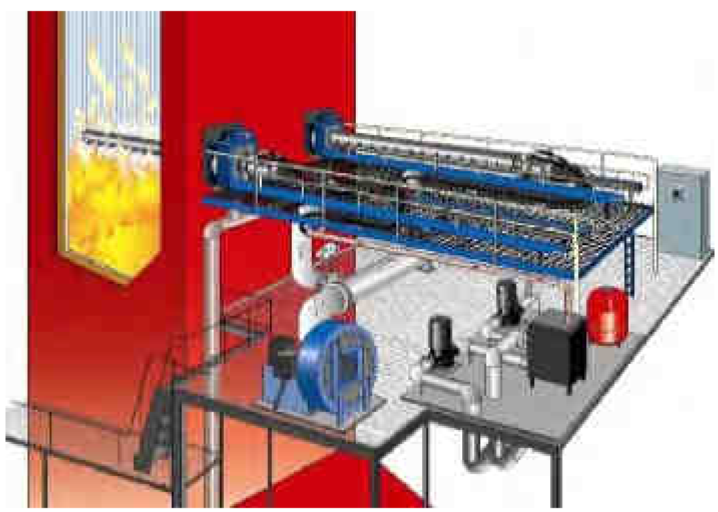

Figure 3-3
ECOTUBE Installation in a Boiler

3.1.5 LoTOx

The LoTOx technology is the low temperature gas-phase oxidation of NO_x by ozone injection. In this method, ozone is injected into the flue gas upstream of a wet FGD system. The ozone reacts with the NO and NO_2 to form nitrogen pentoxide (N_2O_5). The N_2O_5 formed is soluble in water and can be removed from the flue gas using a wet FGD system.

The LoTOx technology has been demonstrated on several industrial sized plants. In May 2002; the technology was used at Abitibi Consolidated (Sheldon, Texas), a paper recycling plant. The Ohio Coal Development Office funded a $6.3 million LoTOx unit at the Medical College of Ohio, and there have been several refinery applications.

The LoTOx technology offers high NO_x removal efficiency with a reported potential of 15 to 25 percent savings in capital cost over an SCR system. The major drawbacks of this system are the lack of experience on larger power generating units, high power consumption, and the production of nitrates.

The high auxiliary power consumption from the multiple ozone generators required to produce the ozone for the process is expected to be comparable to what is needed for a conventional FGD system and is significantly higher than the power consumption from an SCR. The nitrate production from this technology is captured in the FGD waste product, possibly requiring the need for a wastewater treatment plant.

3.1.6 Natural Gas Reburn

The natural gas reburning process employs three separate combustion zones to reduce NO_x emissions, as illustrated on Figure 3-4. The first zone consists of the normal combustion zone in the lower furnace, which is formed by the existing wall burners. In this zone, 75 to 80 percent of the total fuel heat input is introduced. The first zone burners are operated with about 10 percent excess air (a 1:10 stoichiometric ratio). A second combustion zone (the reburn zone) is created above the lower furnace by operating a row of conventional natural gas burners at a stoichiometric ratio less than 1.0. This technology also has the potential for increased furnace corrosion (especially with higher sulfur fuels) because of the reducing atmosphere in the lower furnace.

The substoichiometric reburn zone causes NO_x produced in the lower furnace units to be reduced to molecular nitrogen and oxygen because the oxygen stripped from the NO_x molecules is combined with the more active CO molecules to form carbon dioxide as combustion is completed in the upper furnace. Fuel burnout is completed in the third zone (the burnout zone) by the introduction of OFA. Sufficient OFA is introduced to complete combustion of the unburned materials in the upper furnace with an overall excess air rate for the boiler of 15 to 20 percent. Reburn technology has demonstrated NO_x reduction of 40 to 65 percent.

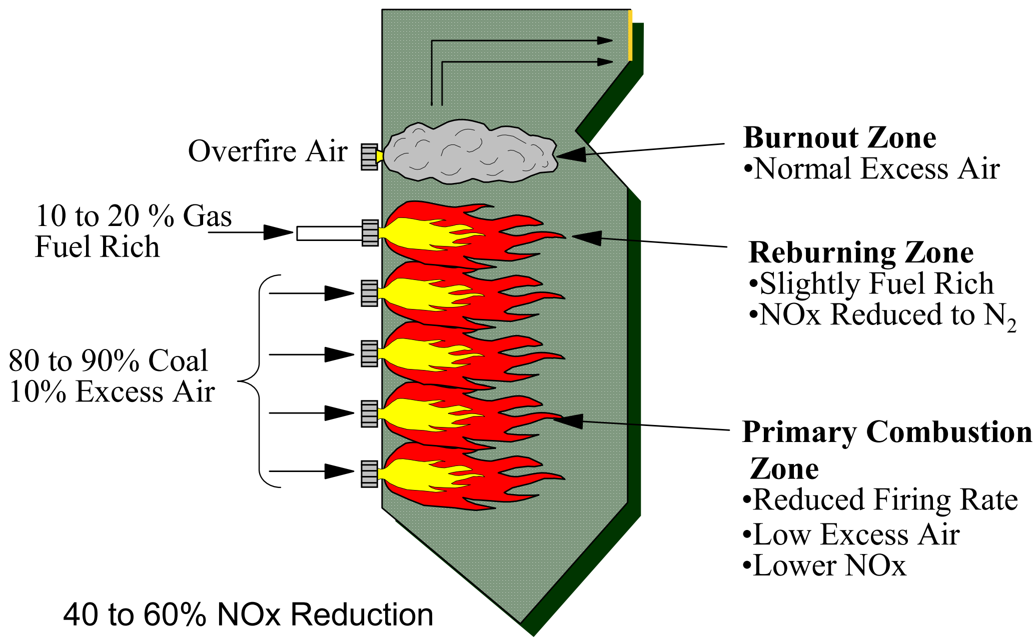

Figure 3-4
Schematic of Gas Reburn System

Sufficient residence time (adequate furnace height) in the reburn and OFA zones is a key factor in determining whether the reburning technology can be applied. Successful retrofit of this technology requires space within the boiler to allow adequate residence time for both the additional burning zone (0.4 to 0.6 second) and the associated OFA burnout zone (0.6 to 0.9 second). When this space is available, reburning can be highly effective, but a low residence time will limit system performance. Also, the high cost of natural gas makes the annual operating costs of this technology prohibitive.

3.2 SO_2 Control Technologies

The following SO_2 control technologies were identified as available for retrofit at the Boardman Plant are summarized in Subsections 3.2.1 through 3.2.4:

- Wet FGD.
- Semi-dry FGD.
- Dry FGD (Circulating Dry Scrubber [CDS]).
- Furnace/duct reagent injection.
- Reduced sulfur coal restriction.

3.2.1 Wet Flue Gas Desulfurization

Although wet lime and ammonia FGD systems are available, the wet limestone FGD process is the most frequently applied FGD technology in the United States when treating flue gas from combustion of medium- and high-sulfur coals (typically greater than 1.5 percent sulfur). Wet limestone FGD systems are also applicable for units burning low-sulfur bituminous and subbituminous coals. Wet limestone FGD systems are capable of achieving slightly higher SO_2 removal than other types of FGD systems but have not demonstrated significant removal of elemental mercury. A typical wet limestone FGD system consists of reagent storage and handling system, FGD spray tower absorber, and byproduct dewatering system as illustrated on Figure 3-5.

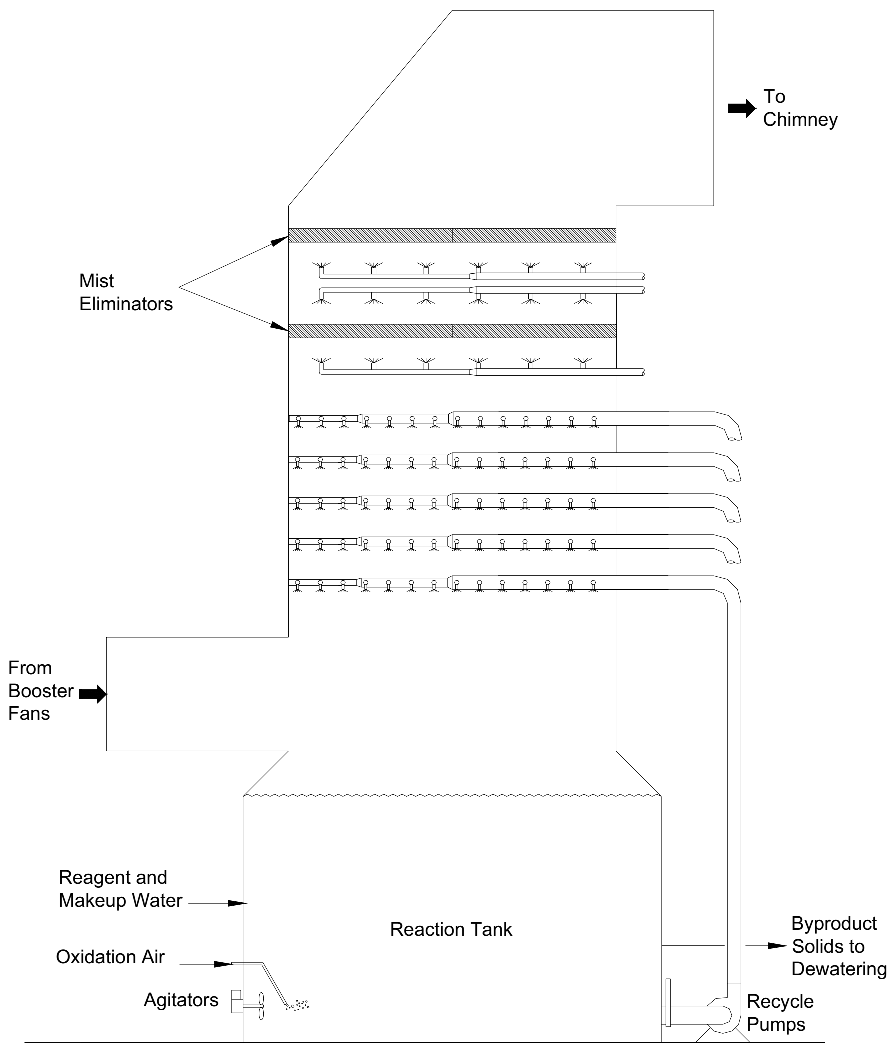

Figure 3-5
Process Flow Diagram of a Spray Tower Wet FGD System.

For most wet limestone FGD applications, the absorber module is located downstream of the ID fans (or booster ID fans, if required). For a wet FGD system, the flue gas enters the absorber and is contacted with a slurry containing reagent and byproduct solids. The SO_2 is absorbed into the slurry and reacts with the calcium to form $CaSO_3 \bullet 1/2H_2O$ and $CaSO_4 \bullet 2H_2O$.

There are several types of absorber modules, and each has characteristic advantages and disadvantages. FGD equipment vendors have specific designs for one or more types, and all compete on a capital/operating cost and guarantee basis. Depending on the process vendor, the absorber may be a co-current or countercurrent spray tower, with or without internal packing or trays. Other vendors use a unique absorber where the flue gas is bubbled into a reaction tank, as illustrated on Figure 3-6. Regardless of the type of absorber used, the flue gas leaving the absorber is saturated with water and the stack will have a visible, persistent moisture plume. Generally, wet FGD systems do not remove significant quantities of SO_3 from the flue gas. Condensed SO_3, in the form of sulfuric acid mist (H_2SO_4), can be removed with a WESP, which is discussed in Subsection 3.3.6.

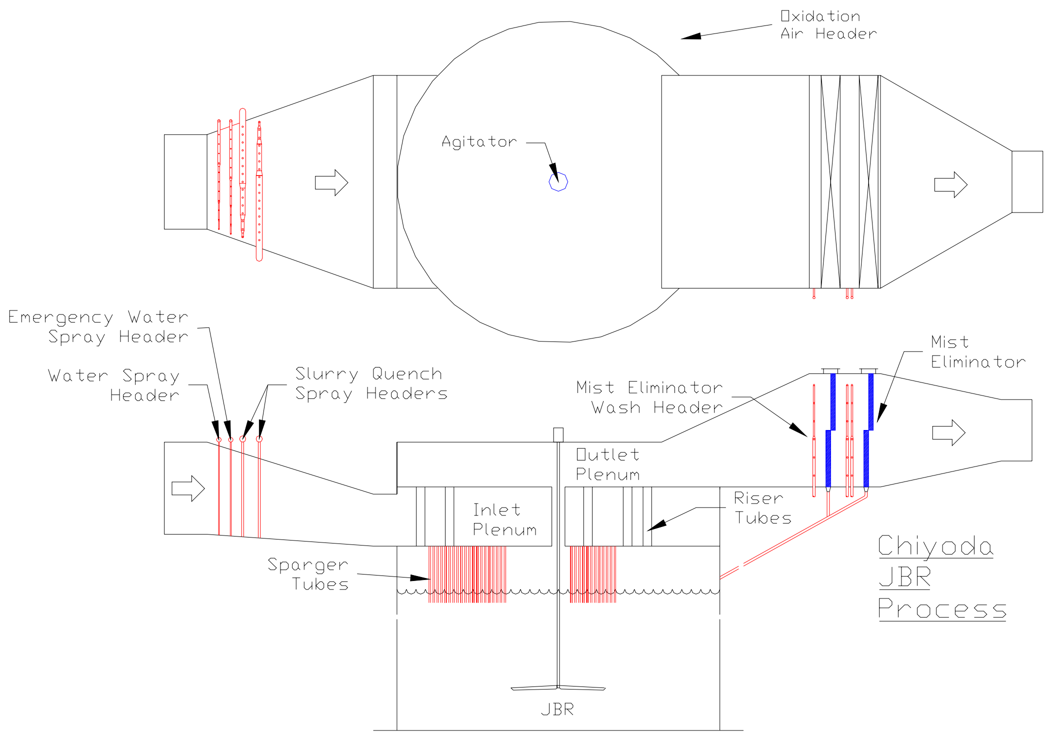

Figure 3-6
Cutaway View of a Jet Bubbling Reactor Wet FGD System

Because of the chlorides present in the mist carryover from the absorber and the pools of low pH condensate that can develop, the conditions downstream of the absorber are highly corrosive to most materials of construction. Highly corrosion-resistant materials are required for the downstream ductwork and for the stack flue. Careful design of the stack is needed to prevent "rainout" from condensation that occurs in the downstream ductwork and stack.

The reaction byproducts are typically dewatered by a combination of hydro-cyclones and vacuum filters. For natural oxidation wet limestone FGD systems, the resulting filter cake is suitable for landfill disposal. In some instances, the FGD byproduct requires mixing with fly ash and/or lime (fixation) to produce a physically stable material.

If air is bubbled through the reaction tank, practically all of the $CaSO_3 \bullet 1/2H_2O$ can be converted to $CaSO_4 \bullet 2H_2O$, which is commonly known as gypsum. This oxidation step is termed "forced oxidation." Compared to calcium sulfite, gypsum has much superior dewatering and physical properties, and forced-oxidized systems tend to have few scaling problems in the absorber and mist eliminators. Dewatered gypsum can be landfilled without stabilization or fixation. Many wet FGD systems in the United States are using the forced-oxidation process to produce commercial grade gypsum that can be used in the production of Portland cement or wallboard. Marketing of the gypsum can eliminate or greatly reduce the need to landfill FGD byproducts.

The wet FGD processes are characterized by high efficiency and high reagent utilization. The absorber vessels are fabricated from corrosion-resistant materials such as epoxy/vinylester-lined carbon steel, rubber-lined carbon steel, stainless steel, or fiberglass. The absorbers handle large volumes of abrasive slurries. The reagent handling and byproduct dewatering equipment is also relatively complex and expensive. These factors result in relatively higher initial capital costs and lower annual operating costs compared to the semi-dry FGD alternatives.

3.2.2 Semi-Dry Flue Gas Desulfurization

The semi-dry FGD process is based on the spray drying of lime slurry into flue gas. This is performed in a spray dryer absorber (SDA). There are numerous SDA FGD system installations on boilers using low-sulfur fuels. These installations, primarily located in the western United States, use either lignite or subbituminous coals as boiler fuel and generally have spray dryer systems designed for a maximum fuel sulfur content of less than 2 percent.

There are several variations of this process, but the most prevalent is the installation of one or more spray dry vessels upstream of a supplied particulate control device, as shown on Figures 3-7 and 3-8. For new plants, the SDA absorber vessel is located between the air heater and the particulate removal device, most commonly a pulse jet fabric filter (PJFF). For the Boardman Plant, the SDA absorber vessel and PJFF would be located downstream from the existing ID fans.

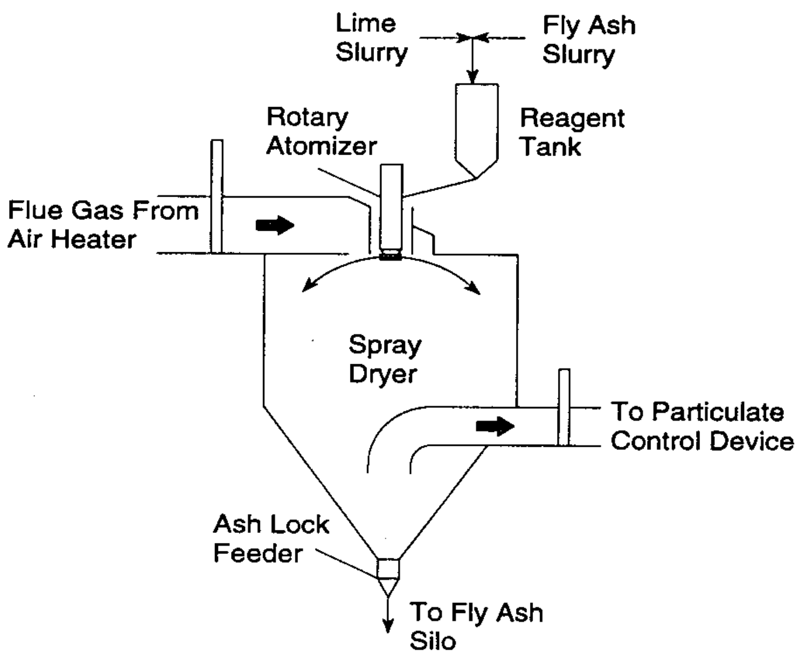

Figure 3-7
Spray Dryer System

Although either quicklime slurry (CaO) or a sodium carbonate (soda ash) solution may be used as the scrubbing reagent, the current generation of SDA FGD processes uses primarily quicklime. The quicklime is first slaked with water to form a calcium hydroxide ($Ca(OH)_2$) slurry. The lime slurry is combined with the recycled solids from the PJFF to form the reagent slurry. The reagent slurry is injected into the absorber using either a rotary or dual-fluid atomizer, where the lime reacts with the SO_2 in the flue gas. Sufficient water is added to the reagent slurry to lower the flue gas temperature to within 32 to 40°F of the adiabatic saturation temperature. The SO_2 is absorbed into the fine spray droplets and reacts with the lime slurry to form both calcium sulfite (~1/3) and calcium sulfate (~2/3). Before the droplets can reach the wall of the vessel, the heat of the flue gas evaporates the droplets to dry particles containing the byproduct solids and excess reagent. As the reagent slurry evaporates, a relatively dry powder remains.

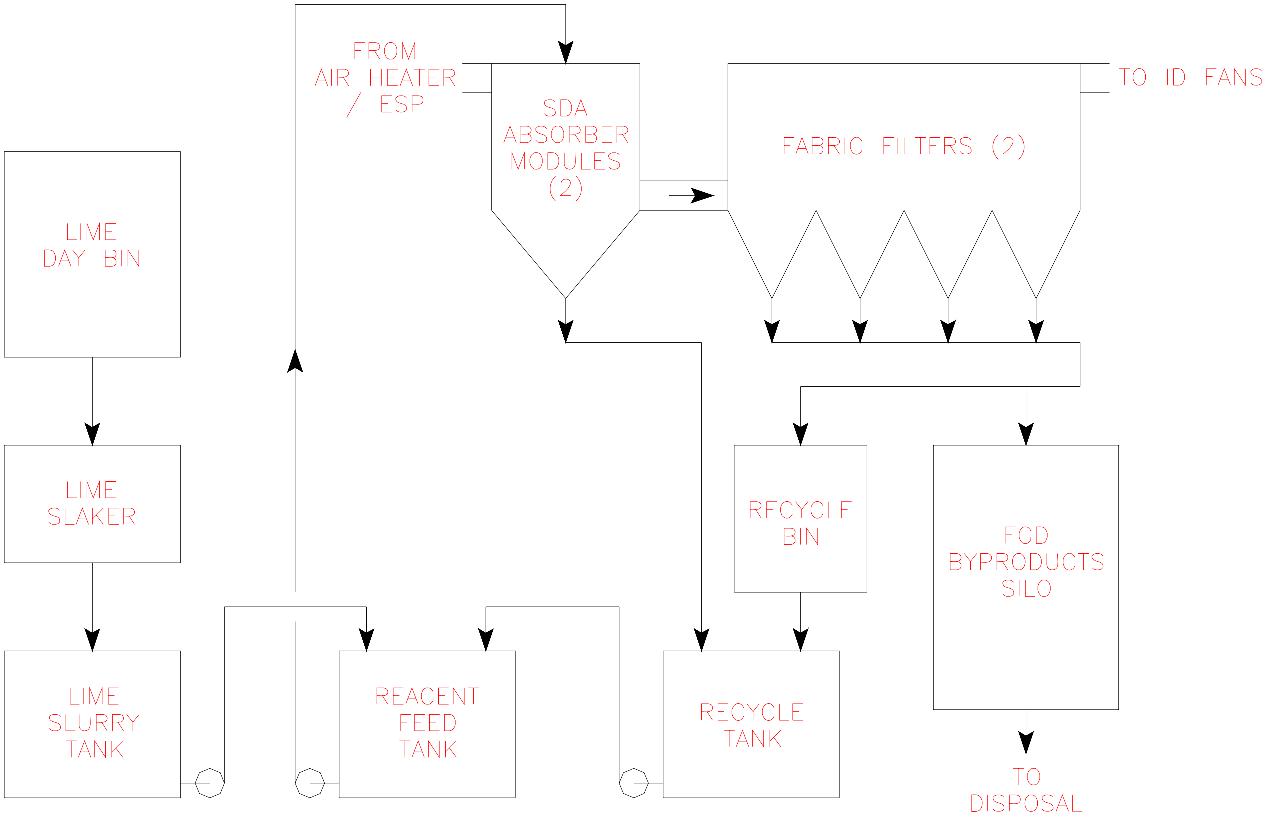

Figure 3-8
SDA FGD System

The byproduct solids and fly ash are collected in the PJFF. The PJFF is always supplied as a system along with the SDA. The PJFF is an integral component of the SO_2 removal system, since a significant percentage of removal occurs as the flue gas passes through the dust cake on the bags. The vendor guarantee is based on the total removal as measured at the exit of the PJFF.

The byproducts and fly ash are conveyed pneumatically to the fly ash silo in the conventional manner. These solids are unloaded, conditioned with water, and transported to a landfill. Because of the level of free lime in the byproduct solids, the byproduct/fly ash mixture attains a very high bearing strength and low permeability in the landfill. Unlike a wet limestone FGD system, there is currently no commercial use for the byproduct/fly ash.

3.2.3 Circulating Dry Scrubber

CDS is a form of dry FGD for SO_2 removal. Hydrated lime ($Ca[OH]_2$) is the reagent used; it is introduced as a dry, free flowing powder into the scrubber vessel. Flue gas is then flowed through the lime reagent in a circulation pattern for adsorption of SO_2 by the lime. A schematic of the process flow of a CDS process is shown on Figure 3-9.

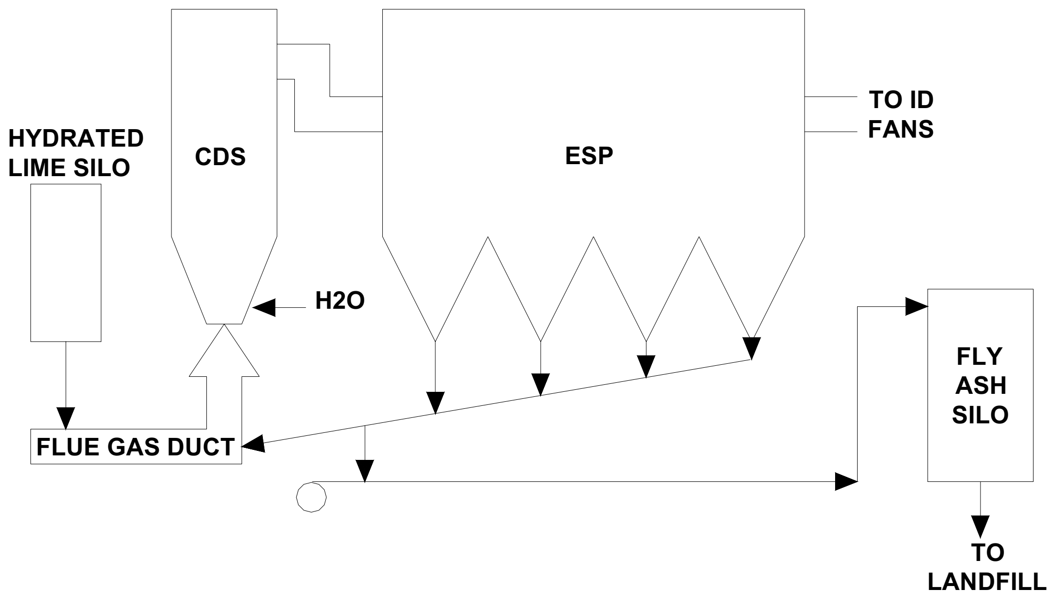

Figure 3-9
Circulating Dry Scrubber System (Lurgi Lentjes North America)

Generally, there are no constraints on the maximum fuel sulfur content; the CDS can be adjusted to account for the higher SO_2 loading by increasing the concentration of reagent. However, this flexibility is limited by the cost of the lime reagent. An evaluation on the overall reagent cost is important before selecting this technology. Lime utilization is improved by cooling the flue gas before it reacts with the lime. Flue gas coming into the scrubber vessel is cooled to about 30^{o} F above the adiabatic saturation temperature.

As is the case with the SDA, a downstream particulate collection device is required, usually an ESP or FF, for the removal of PM from the ash in the coal and the product of the reaction of lime with the SO_2 in the flue gas. Because of the relatively high velocity of the flue gas through the scrubber vessel (approximately 19 ft/s), the treated flue gas carries entrained reagent and reaction products from the module to the downstream particulate control device.

Over 90 percent of the collected solids in the ESP or FF contain unreacted lime. Because of abrasion and impacts of the other particles in the flue gas as well as material handling dynamics, the “shell” of reaction products on the reagent particles is broken up. This material is recycled into the scrubber vessel to further improve lime utilization. This solids recirculation also maintains the bed densities needed for contact and removal of SO_2. Typically, reagent is recirculated 35 to 50 times, providing a residence time of 30 minutes or more. Collected solids, which are not recirculated, are disposed of.

The CDS is a small vessel; the associated ESP or FF is in an elevated location because flue gas travels upwards in a CDS vessel. This arrangement results in a smaller footprint for applications with space constraints. However, depending on the site situation, the retrofit of such a system might be costly, especially if there are substantial construction and structural difficulties.

Disadvantages of this process include high dust loading at the particulate removal system and lack of US utility operating experience in the size range of the Boardman Plant. Higher FF pressure drops are encountered because of the flue gas dust loading, thus ESPs are preferred for particulate removal. The high particulate loadings make sizing of the ESP critical to ensure compliance with particulate emission requirements.

3.2.4 Furnace/Duct Reagent Injection

Furnace and duct reagent injection systems require either a wet or dry reagent such as sodium bicarbonate, powdered lime, hydrated lime, lime slurry, limestone or $Mg(OH)_2$ to remove SO_2. This technology is typically capable of removing between 20 to 50 percent of the SO_2 in the flue gas, and its removal efficiency is highly dependent on the application, primarily the configuration of the existing ductwork and the flue gas residence time in the ductwork.

Because of the type of reaction, temperature, percentage reduction rate, and the corresponding retention time requirements, a dry reagent such as powdered lime and hydrated lime are preferred for furnace injection applications. A wet reagent, such as lime slurry, sodium bicarbonate, or $Mg(OH)_2$, is typically preferred for duct injection applications because of the removal requirements and the flue gas properties.

The use of a wet reagent for duct injection is preferred over a dry reagent because of the elevated gas temperatures that exist during normal operating conditions. The use of a wet reagent upstream of an existing ESP will help reduce the gas temperature, improve ESP performance for opacity and particulate control, and eliminate the need for additional ID booster fans for additional draft control.

CFD and chemical kinetic modeling may be necessary to determine which reagent is preferred; the preferred location of reagent injection; the amount of SO_2 emissions removed; and whether furnace injection, duct injection, or both furnace/duct injection systems are required for effective removal. Unit design and operational data will be collected for the CFD computer model inputs. This data, combined with unit mapping information, will enable the model to develop precise injection locations and reagent injection characteristics for each boiler.

The major components of a typical reagent injection system include an air compressor, chemical storage tank, heat tracing, controls, injection system (e.g., flanges, lances, nozzles, hoses, hardware, etc.), injection platform, and slurry pump.

Furnace injection can reduce or eliminate fireside slagging, fouling, corrosion, and erosion problems in the furnace. Other benefits of various efficiency improvements include savings through greater heat transfer cleanliness, reduction of periodic air heater replacement, increase in overall unit reliability, reduction of boiler cleaning costs, and, ultimately, the extension of unit runs to the point where only scheduled outages are taken.

3.2.5 Reduced Sulfur Coal Restriction

Reduced sulfur coals are available that could reduce SO_2 emissions without the negative ancillary impacts associated with post-combustion controls. Reduced sulfur coal could be used to reduce SO_2 emissions but would require coal blending to achieve material reductions. Seams within existing Powder River Basin coal mines have different sulfur levels. However, only a limited number of mines offer the lowest sulfur coals and those coals are facing increasing demand. Not all portions of those limited mines contain reduced sulfur coal. In addition, seasonal transportation restrictions can limit the availability of certain coals at certain times of year. As a result, any significant reduction in the Boardman Plant boiler's SO_2 emission limit through the use of lower sulfur coals would need to be accomplished through the blending of coals with different sulfur levels.

PGE could reasonably lower its SO_2 emission limit to 0.96 lb/MMBtu (a 20 percent reduction from the present SO_2 emissions limit) by December 31, 2011. The Boardman Plant has contractual commitments for fuel supply in place through December 31, 2011. These contractual commitments allow the vendor to provide coal with SO_2 emissions up to 1.2 lb/MMBtu. PGE cannot breach these contracts without severe long term ramifications and so cannot decrease its SO_2 emissions limit until those contracts expire on December 31, 2011. Once new contracts are in effect, PGE can begin purchasing reduced sulfur coals.

However, the Boardman Plant has an existing stockpile of approximately 500,000 tons of coal provided under contracts that allowed up to 1.2 lb/MMBtu SO2 (as emitted) consistent with the current permit limit. The stockpiled coal would need to be blended in with the coal provided under the new contracts. The coal in the stockpile has a mineral composition that creates a destructive slagging and fouling if burned in large percentages. In order to avoid damage to the boiler, the Boardman Plant only burns a limited percentage of this stockpiled coal at any one time. Based on the estimated maximum reasonable firing rate for the stockpiled coal and the use of reduced sulfur coals contracted for starting on January 1, 2012, the Boardman Plant boiler could decrease its SO_2 emissions limit by 20 percent (i.e., to 0.96 lb/MMBtu). Any lower value would prolong the time period necessary to consume the stockpiled coal. At a maximum reasonable firing rate and taking into account projected outage periods, the Boardman Plant boiler would require through June 30, 2014 to consume the existing fuel stockpile without material risk of damage to the boiler. Once that stockpiled coal is fully consumed, the SO_2 emissions limit could be further reduced.

PGE could reasonably lower its SO_2 emission limit to 0.60 lb/MMBtu (a 50 percent reduction from the present SO_2 emissions limit) starting on July 1, 2014. Once the stockpiled coal is consumed, the Boardman Plant boiler can begin blending exclusively reduced sulfur coals. Based on an assessment of the mines with reasonable transportation accessibility and taking into account the need for maintaining a reliable supply through 2020, it would be reasonable to reduce the SO_2 emissions limit to as low as 0.60 lb/MMBtu. Compliance with this SO_2 emissions limit could be accomplished by using a blend of the coal supplies that are reasonably projected to be available in adequate quantities and are compatible with the Boardman Plant boiler. Trying to consistently attain an SO_2 emission limit lower than 0.60 lb/MMBtu would impose excessive availability, risk and cost burdens on the plant and so is not considered feasible.

Both the 0.96 lb/MMBtu and the 0.60 lb/MMBtu SO_2 emissions limits would need to apply on an annual average basis. Any shorter term averaging period would require higher limits to account for natural variation in supply and sulfur content.

3.3 PM Control Technologies

The following PM control technologies were identified as available for retrofit at the Boardman Plant and are summarized in Subsections 3.3.1 through 3.3.6:

- PJFF.
- Compact Hybrid Particulate Collector (COHPAC).
- GE MAX-9 hybrid.

- Multi-cyclone
- WESP.

3.3.1 Pulse Jet Fabric Filter

FFs are media filters that the flue gas passes through to remove particulate. Reduced particulate emissions limits and the selection of low-sulfur fuels has promoted the use of FFs for the last 15 years.

Cloth filter media is typically sewn into cylindrical tubes called bags. Each FF unit may have thousands of these filter bags. The filter unit is typically divided into compartments that allow online maintenance or bag replacement. The quantity of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth (A/C) ratio, and cleaning system design. Each compartment includes at least one hopper for temporary storage of the collected fly ash. A cut-away view of a PJFF compartment is illustrated on Figure 3-10.

Fabric bags vary in composition, length, and cross section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, A/C ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years.

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tube sheet.

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This releases the dust cake from the bag surface. The dust then falls into the hopper. This cleaning may occur with the compartment online or offline. Care must be taken during design to ensure that the upward velocity between the bags is minimized so that particulate is not re-entrained during the cleaning process. The PJFF cleans bags in sequential, usually staggered, rows. During online cleaning, part of the dust cake from the row being cleaned may be captured by the adjacent rows. Online PJFF cleaning has been successfully implemented on many large units and is a standard feature of the technology.

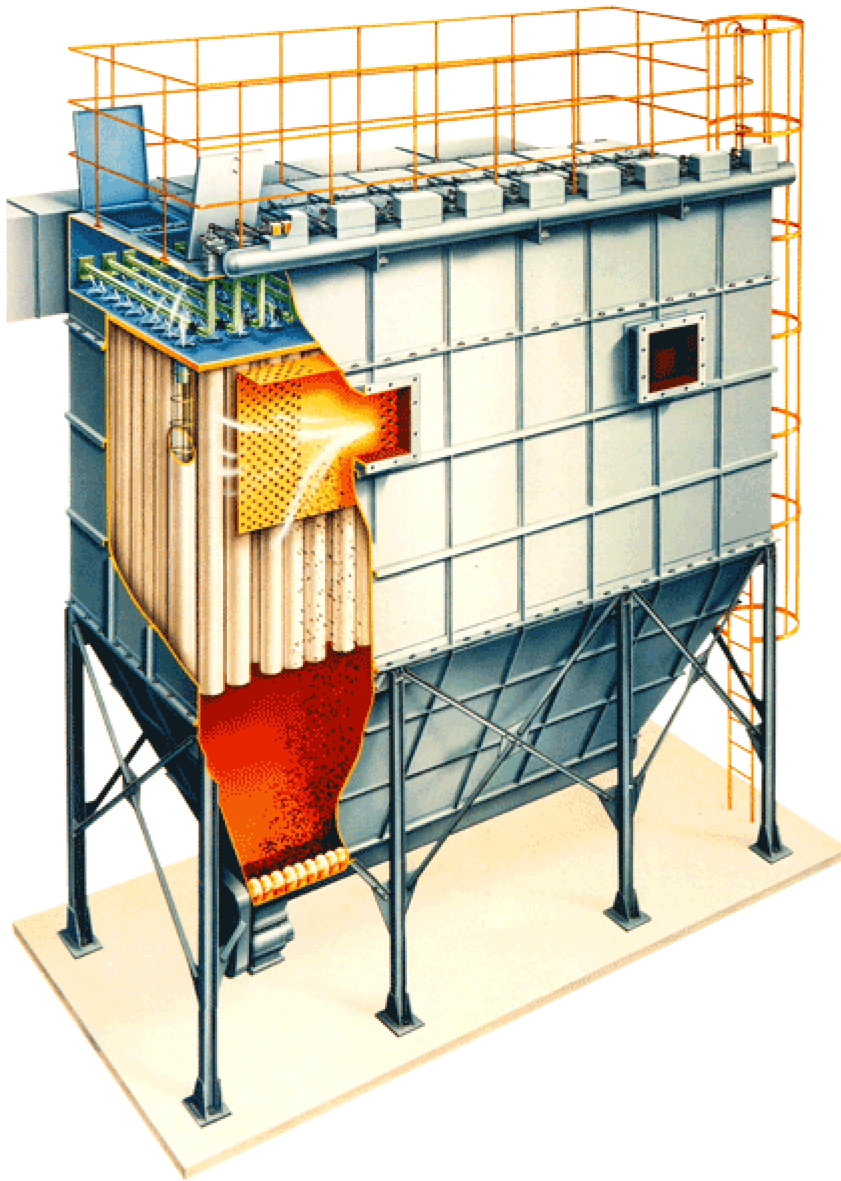

Figure 3-10
Pulse Jet Fabric Filter Compartment (Babcock & Wilcox)

3.3.2 Compact Hybrid Particulate Collector

Another control technology that is effective in removing particulate is a high A/C ratio FF installed after an existing cold-side ESP. Commonly referred to as a COHPAC, this technology was developed and trademarked by the Electric Power Research Institute (EPRI). The COHPAC filter typically operates at A/C ratios ranging from 6 to 8 ft/min., compared to a conventional FF that typically operates at A/C ratios of about 4 ft/min.

The majority of the particulate is collected in the upstream ESP. Therefore, the performance requirements of a high A/C ratio FF is reduced, allowing installation of this technology in a smaller footprint area and with less steel and filtration media, which has the potential to lower capital and operating costs compared to conventional FFs. However, the performance of the FF for a COHPAC system is different than for a regular FF system, because the majority of large particulates are removed in the ESP, leaving only smaller particles to be collected by the FF. The smaller particles become embedded into the bag material. The bags with imbedded particulates are more difficult to clean.

3.3.3 GE MAX-9 Hybrid

The Max-9 electrostatic filter is a hybrid combination of a high-efficiency PJFF and an ESP without collecting plates. A front and side elevation view of the Max-9 particulate filter is illustrated on Figure 3-11. When the dust particles are charged, they are attracted to the grounded metal cage inside the filter element, just as they would be attracted to the collecting plates in an ordinary precipitator. Since the particles are positively charged, they repel each other on the surface of the filter, making the collected dust cake very porous. This results in a reduction of filter drag at a pressure drop about 25 percent of a normal FF. Consequently, the Max-9 can operate at an A/C ratio higher than a conventional FF and can treat a significant gas volume with a smaller footprint.

Process gas enters the Max-9 from a hopper inlet duct. The gas then flows upward through the filters and out through the top of the filters. The area above the tube sheet is a clean gas plenum. Compressed air pulses are used to clean the filters. A brief, intense blast of air is fired through the purge air manifold; holes in the blowpipes located above the filters direct the cleaning air pulse down through the filters. The cleaning sequence is controlled by timers that trigger solenoids. The high voltage system operates at very low current densities and at a steady state. There is no danger of fire caused by sparking, and the transformer/rectifier requires no voltage control.

The Max-9 can be supplied as shop-assembled modules that can be erected on site, although the units are usually custom-engineered for each plant site and application to make the best use of available space.

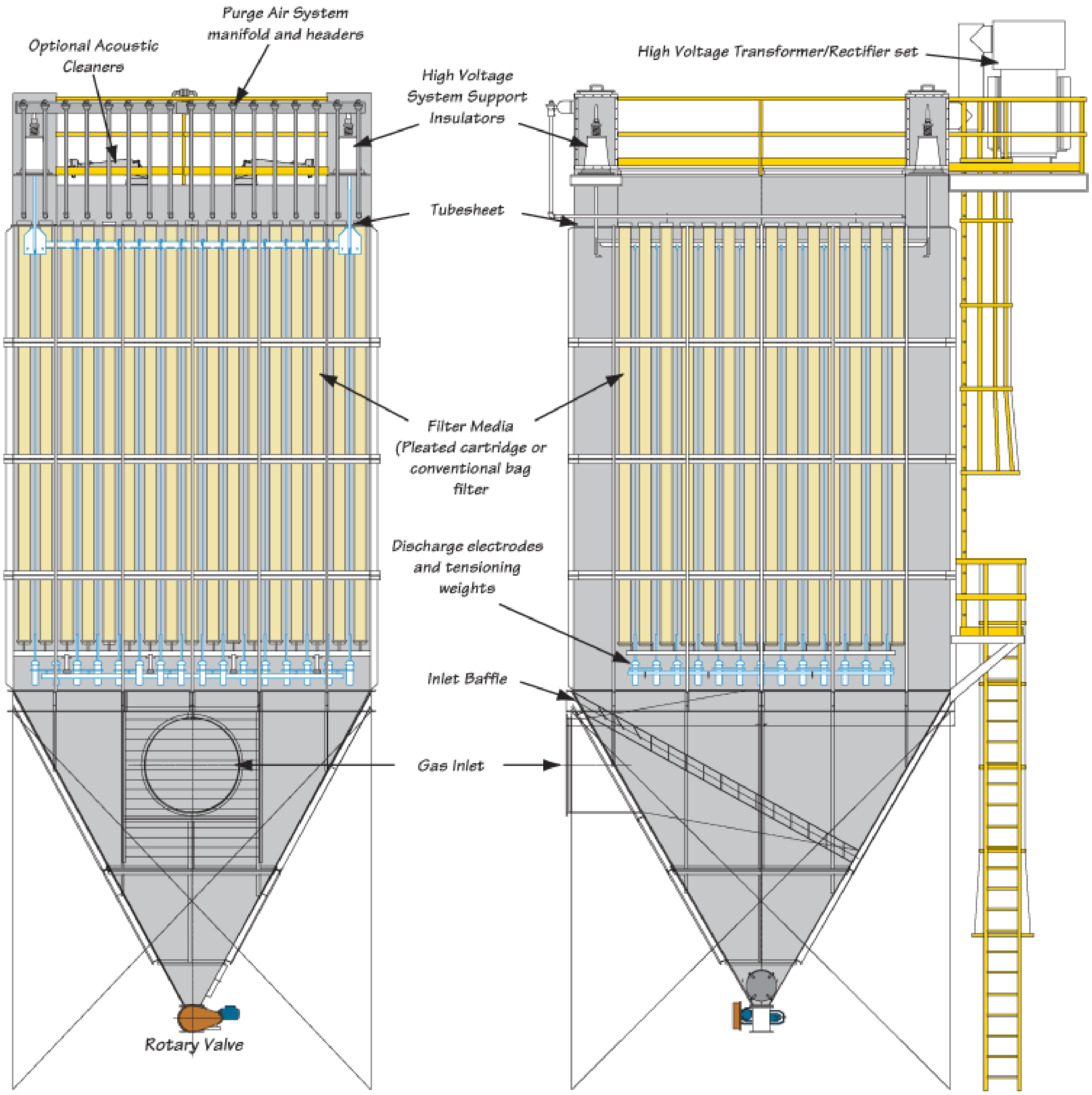

Figure 3-11
Max-9 Electrostatic Filter

3.3.4 Multiple-Cyclone Separators

Multiple-cyclone separators, also known as multiclones, consist of a number of small-diameter cyclones, operating in parallel and having a common gas inlet and outlet, as shown on Figure 3-12. Multiclones operate on the same principle as cyclones--creating a main downward vortex and an ascending inner vortex. Multiclones are more efficient than single cyclones because they are longer and smaller in diameter. The longer length provides longer residence time, while the smaller diameter creates greater centrifugal force. These two factors result in better separation of dust particulates. The pressure drop of multiclone collectors is higher than that of single-cyclone separators.

Cyclone collectors are centrifugal collectors that rely on the particle density and velocity to separate the fly ash from the flue gas. The particulate-laden flue gas enters the top or the side of the cyclone. An illustration of the components and working principles of a multiclone is shown on Figure 3-12. Vanes impart a rotational velocity to the flue gas, driving the fly ash to the edge of the cylinder. The flue gas then exits the center of the cyclone out the top, leaving the fly ash to fall out the bottom. At pressures near one atmosphere and 2 to 5 in. wg pressure differential, this technology can effectively remove particles larger than 20 microns in size; particles less than 10 microns are usually unaffected and not removed.

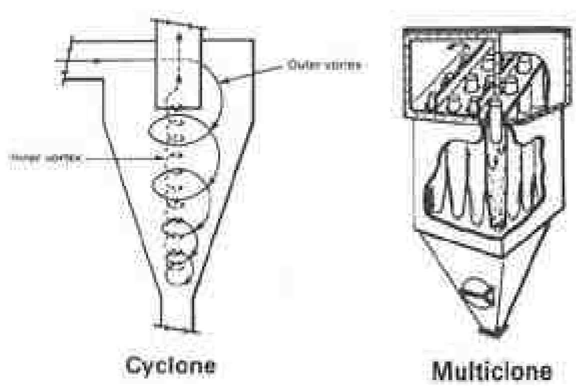

Figure 3-12
Multiple-Cyclone Particulate Collector

3.3.5 Wet ESP

A WESP collects particles on the same theoretical basis as a dry ESP: negatively charged particles are collected on positively charged surfaces. The collecting surfaces are wet instead of dry and are flushed with water to remove the particulate. Typically, a WESP is installed downstream of an existing wet FGD system where the flue gas is already saturated, so the amount of added water is minimized. The particulate collection efficiency is enhanced by a lack of re-entrainment after contact with the wet walls (as contrasted with re-entrainment due to rapping on a dry ESP). Therefore, the WESP is well suited for fine particulate or acid mist applications because it reduces opacity, sulfuric acid mist (H_2SO_4), and other aerosols.

The use of WESPs for acid mist collection was one of the earliest applications for ESPs. Although there are few applications in the utility industry, this is a mature technology with hundreds of industrial installations. The particulate characteristics, temperature, and humidity in WESPs provide excellent fuel flexibility regarding particulate removal. However, water chemistry, scaling, and corrosion potential need to be carefully investigated.

The WESP collecting fields impart a negative charge to the particles and collect them on positively charged collecting electrodes. Each collection field is equipped with independent electrical bus sections, each of which has a dedicated high voltage transformer/rectifier and controller. The controllers for each transformer/rectifier are located in an environmentally controlled enclosure. Each electrical field has a separate discharge electrode support frame suspended by alumina insulators. A heater-blower system dedicated to each module supplies warm purge air for each of the insulator compartments. The discharge electrode support frames are constructed from Type 304 stainless steel. The discharge electrodes are suspended from the upper guide frame and held in the tube center line. The discharge electrode is a rigid electrode constructed from 304 stainless steel; it contains split corona-generating elements that are welded to the electrode in an opposed orientation.

A WESP can be installed in either horizontal or vertical gas flow orientation. In a horizontal gas flow orientation, a WESP is similar to a common dry ESP. The collection plates are arranged in parallel horizontal paths with discharge electrodes hanging between them. Vertical gas flow WESPs are usually of the tubular collection plate type. The collection plates are arranged in an array of vertical pipes or channels with a discharge electrode hanging down the center of the pipe or channel. Channel shapes such as squares or hexagons have more efficient packing densities than circular pipes (with a small loss in the maximum voltage that can be applied before sparking) and are more common. Where multiple electrical stages are used (analogous to the electrical fields in a horizontal gas flow ESP), the stages are stacked one above the other. Two to three fields are common.

Several major hurdles exist with the use of a WESP. First, the flue gas must be saturated with moisture prior to entering the ESP to allow the WESP to work correctly. Therefore, a quenching system must be installed to add water to the flue gas to reduce the flue gas temperature to the saturation point or the WESP must be installed downstream of an existing wet FGD system. Without the presence of a wet FGD system, the use of a WESP adds additional cost, increases water demand on the plant, and generates a visible moisture plume at the stack outlet. The removed particulate would be contained in a wastewater stream that is generated by the WESP. In addition to this issue, the capital cost of a WESP is high compared to other technologies because of the higher cost of the alloy materials required for the WESP. Higher grades of material are required to withstand the highly corrosive conditions presented by the wet and acidic flue gas stream that will be collected in the wastewater stream. Alternatively, addition of alkaline reagents can be used to neutralize the acid in the wastewater stream.

Each WESP module is cleaned by spraying flush water over the WESP components. Flush water is sprayed in the WESP at different spray levels. It is anticipated that each WESP module will be flushed once per day. Individual electrical sections of each field may be flushed online while the power is turned off to the electrical section being cleaned.

If the WESP system is installed downstream of a wet FGD system, there is a potential for gypsum scale to form because sulfuric acid and calcium may be carried over from the scrubber into the WESP. A continuous injection of dispersant into the system can be employed to help eliminate scale formation within the module. The dispersant can be stored in a small tank and fed into the flush water surge tank to allow dispersant to enter the modules through the spray levels. In addition to this control of the water chemistry in the WESP, periodic out-of-service cleaning of a more intense nature might be required. Physical cleaning using high-pressure water jets (“hydro lasers”) or chemical flushing using an acid based solvent to dissolve the scale buildup are two potential options.

3.4 Emerging Pollution Control Technologies

Research is ongoing to develop new and improved technologies for multi-pollutant control. The list of emerging technologies is numerous, and the technologies with the most promise include the PowerSpan ECO and Enviroscrub systems. Several other promising emerging technologies, such as the Airborne system, are also in the early stages of development but are not as far along in pilot testing as the others. Since many of these technologies are still at the pilot (slipstream) stage of development, they should be viewed with caution until more is known and performance guarantees become available.

3.4.1 PowerSpan

There are several emerging multi-pollutant technologies that use high electron beams or other proprietary processes. The PowerSpan ECO system has only limited experience and has not been fully tested on full-scale systems. The ECO system is located downstream of an existing particulate control device, and the process consists of three stages. In the first stage, the flue gas passes through a barrier discharge reactor where it is exposed to a high voltage discharge that generates high energy electrons. The electrons initiate a chemical reaction that forms oxygen and hydroxyl radicals, which then oxidize NO_x, SO_2, and mercury. This reaction results in the formation of nitric acid, sulfuric acid, and mercuric oxides. A process flow diagram of the ECO system is illustrated on Figure 3-13. Stage 2 is the collection of these acids and oxides in a downstream ammonia scrubber. The final stage is the collection of acid aerosols, fine PM, and oxidized mercury in the downstream WESP. Scrubber effluents contain dissolved ammonium sulfate nitrate (ASN) salts along with solids and mercury. The ASN solution is sent to a recovery process where the mercury is removed via a sulfur-impregnated activated carbon structure. Once the carbon activated bed becomes saturated with mercury, it is disposed of as a hazardous waste. The cleaned stream of ASN is converted to a saleable fertilizer.

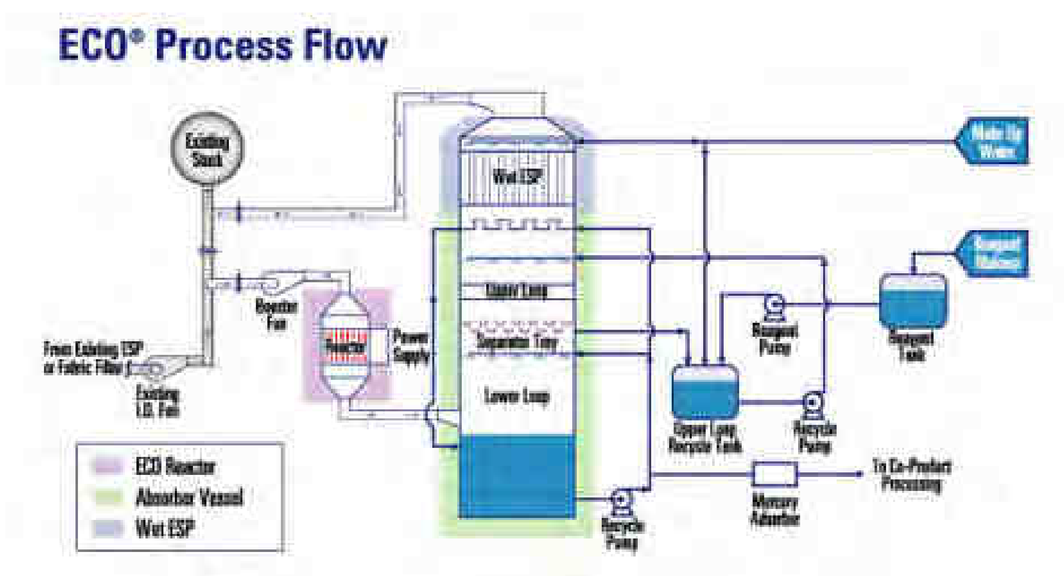

Figure 3-13
ECO Process Flow Diagram (PowerSpan).

PowerSpan also offers a mercury-only control technology that uses a photochemical oxidation process. In this process, mercury is oxidized via ultraviolet lights. The ultraviolet lights are placed in the ductwork upstream of the particulate control device. Photochemical oxidation technology is in its infancy stage, as are most mercury reduction technologies.

The ECO system is under pilot testing at FirstEnergy's 50 MW Burger Plant and has achieved 82, 99, and 85 percent reduction for NO_x, SO_2, and mercury, respectively, while combusting eastern high-sulfur bituminous coal. However, because the ECO system has not been pilot tested at a facility burning a low-sulfur (less than 1.5 percent) subbituminous coal or within the Boardman Plant size range, this system was not evaluated further.

3.4.2 Enviroscrub

Enviroscrub is a multi-pollutant control technology that is capable of removing significant amounts of elemental and oxidized mercury, NO_x, $PM_{2.5}$, and SO_2. This technology is based on the Pahlman Process. A sorbent made up of oxides of manganese called Pahlmanite sorbent is injected upstream of the SDA, where the flue gas mixes with the Pahlmanite sorbent. This is where the oxidation and adsorption of mercury takes place. Other pollutants, such as SO_2 and NO_x, are also adsorbed by the Pahlmanite sorbent at this stage. The SDA byproducts are then separated from the flue gas in the PJFF. The fly ash and waste byproduct collected in the PJFF hopper is eventually transported to a slurry tank for subsequent Pahlmanite sorbent regeneration in a reactor. A process flow diagram of the Pahlman Process is illustrated on Figure 3-14.

The configuration for this technology is as follows: particulate removal (existing ESP), SDA, PJFF, sorbent regeneration, and byproduct separation. Currently, Enviroscrub is performing slip-stream pilot testing using third-party contractors, and the initial results are encouraging (Hammel, Charlie; Enviroscrub Technologies Corp., "Pahlman Process Shows Promise," *Power,* Vol. 148, Nov. 8, October 2004, pp. 60-63). The technology is considered to be developing; but it has not yet moved beyond pilot-scale testing and was not evaluated further.

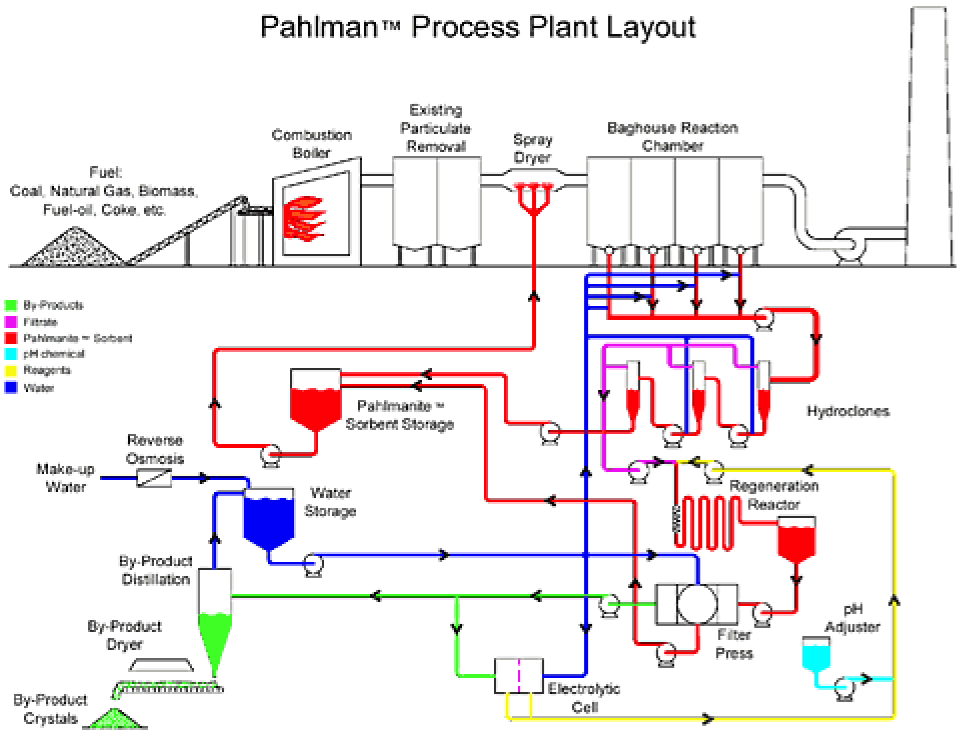

Figure 3-14
Pahlman Process Simplified Process Flow Diagram.

3.4.3 Phenix Clean Coal

The Clean Combustion System (CCS) is an advanced hybrid coal gasification/combustion process that prevents the formation of NO_x and SO_2 emissions when coal is burned. The only reagent required for pollution control is limestone.

The CCS concept is that an entrained-flow coal gasifier is followed by stages of combustion air. The CCS burner is designed to provide the necessary time, temperature, and stoichiometry required for all the chemicals in coal to complete their combustion reactions (to reach equilibrium conditions).

The coal, with limestone added as a source of calcium for sulfur capture, is pulverized and introduced to the burner along with a limited amount of hot combustion air. The initial high-temperature combustion gasifies and/or releases all the constituents of coal into the gas; i.e., carbon, sulfur, nitrogen, and ash compounds. At these high temperatures and with limited available oxygen, the carbon aggressively commands oxygen to form CO from all sources, including such compounds as water (H_2O). Nitrogen compounds that may form, such as NO_x, hydrogen cyanide, and ammonium, are simply forced to the molecular form (N_2) by the aggressive action of carbon for oxygen. In the presence of calcium, the sulfur reacts to form calcium sulfide (CaS), a solid non-gaseous particle).

The high combustion temperatures melt the coal ash and CaS solids to form an inert slag that drains from the bottom of the boiler. Hot gases, high in CO and H_2 and nearly free of NO_x and sulfur, exit into the boiler furnace. As the gases cool and generate steam, additional OFA is added in stages to the furnace to complete the combustion of CO to CO_2 and H_2 to water. This action prevents the formation of any new (thermal) NO_x and completes the combustion with excess air. The clean hot gases then enter the boiler superheat section as before the retrofit. A schematic of the process is shown on Figure 3-15.

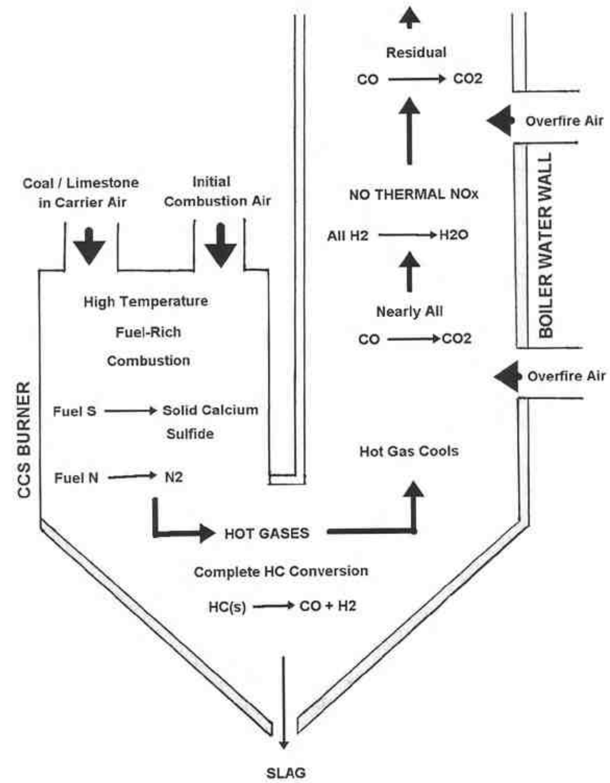

Figure 3-15
Phenix Clean Coal Process Flow Diagram

Retrofits require an annual outage period with a 2 to 3 week extension. The CCS retrofit modification requires replacing the existing pulverized coal burners with new down-fired CCS burners and adding separated OFA to the boiler furnace and powdered limestone to the coal fuel. Most of the new, off-the-shelf equipment fits within the existing boiler space.

The Phenix CCS technology is not in use at a commercial-scale installation with a similar-sized boiler as that at the Boardman Plant. Therefore, the technology was not considered to be technically feasible for application at the Boardman Plant and was not evaluated further.

3.4.4 J-Power ReACT System

Japan's J-POWER is the developer of this enhancement to the original Bergbau Forschung activated coke (AC) process. The original and the enhanced versions of the technology have been installed at several industrial facilities in Japan, as well as at Isogo Unit 101, a 600 MW pulverized coal power plant, and at the Takehara Station, a 350 MW atmospheric fluidized bed combustion (AFBC) boiler. Regenerative Activated Coke Technology (ReACT) is offered in the United States by J-POWER EnTech, Inc.

The J-POWER ReACT system consists of an AC process that involves three steps: (1) adsorption, (2) regeneration, and (3) byproduct recovery**.** Figure 3-16 illustrates the J-POWER ReACT System. The process consists of an adsorber[10] located after the primary particulate control devices and a sorbent regenerator. In the adsorber, the flue gas passes through a bed of AC moving slowly downward at a constant flow rate. The adsorber is of a single-stage design. AC pellets are circulated by a conveyor between the adsorber and regenerator, and ammonia is injected into the flue gas, typically as it enters the adsorber. SO_2, SO_3, NO_x, mercury, and additional particulates (along with associated trace metals) are removed in the adsorber in one step, and the pollutant saturated AC is regenerated in the regenerator, where it is conveyed through a bucket elevator.

The regenerator operates at temperatures in the 750° F to 930° F range. Simultaneously, sulfuric acid or ammonium compounds in the AC are decomposed to nitrogen (N_2), SO_2, and water. Mercury is retained in the AC and removed from the unit every few years, depending on the mercury concentrations at the inlet of ReACT. After cooling, the regenerated AC passes through a vibrating screen to eliminate the mechanically degraded AC and captured dust; then, it is returned to the adsorber. The degraded AC can be returned to the boiler for burning, but it can also be sold and used in other industrial applications, such as dioxin adsorbent. SO_2-rich gas from the regenerator is converted to a salable product, such as sulfuric acid and gypsum, in the byproduct recovery facility.

[10] The term "adsorption" refers to a surface chemical reaction where the reaction products remain on the surface of the solid sorbent material. Because ReACT relies on adsorption of mercury onto activated coke, its reaction vessel is termed an "adsorber." "Absorption" refers to a chemical reaction in which the material (the solute) is absorbed into the bulk of the solvent medium. An example is the absorption of SO_2 in an alkaline liquid in a wet spray tower, and its reaction vessel is termed an "absorber."

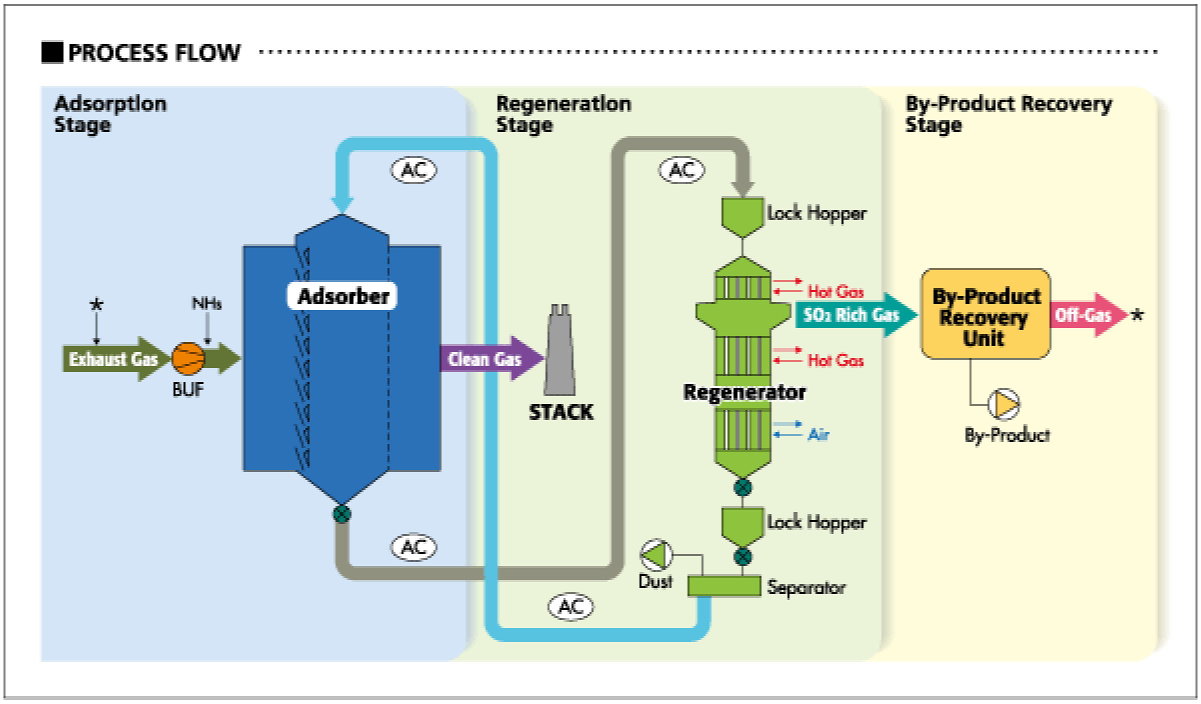

Figure 3-16
J-POWER ReACT System

Unlike the original installations of 10 to 20 years ago, this process uses just one adsorber for all the pollutants, and the coke pellets have been reformulated to be more durable. These upgrades have substantially reduced adsorber size and coke attrition. Consequently, they have reduced the capital cost, coke replacement cost, and required footprint.

Lastly, slipstream testing has demonstrated 90 percent mercury removal with the ReACT system. An EPRI slipstream test of the technology is currently under way at North Valmy Station. The ReACT technology is not in use at a commercial-scale installation in North America with a similar-sized boiler as that at the Boardman Plant burning PRB coal. Therefore, the technology was not considered to be technically feasible for application at the Boardman Plant and was not evaluated further.

4.0 Technically Feasible Retrofit Emission Control Technologies (Step 2)

Step 2 of the BART/Reasonable Progress analysis consisted of limiting the list of potential control technologies developed in Step 1 by eliminating technically infeasible options. In order for a technology identified in Step 1 to be included in the list of technically feasible controls developed in Step 2, that technology must be technically feasible. The EPA has defined "technically feasible" as meaning that a technology is both available and applicable. A technology is considered available if it has reached the licensing and commercial sales stage of development. For example, technologies in the pilot-scale testing stages of development are not considered available. The fact that a technology is considered available is not a sufficient basis for concluding that a technology is applicable, and, therefore, technically feasible. That technology must have been used in the same or a substantially similar source type to be considered applicable.

For all the technologies identified as available in Section 3.0, a determination was made on the technical feasibility of the technology at the Boardman Plant site according to the evaluative process identified by the EPA.

4.1 Technically Infeasible NO_x Control Technologies

4.1.1 ECOTUBE

Since most of the existing installations of the ECOTUBE system are on industrial/small-sized boilers firing solid waste, wood, or biomass, this technology is not technically feasible for the size range of the Boardman Plant.

4.1.2 LoTOx

The LoTOx system has only been demonstrated on small-sized medical waste combustors. It is therefore considered as not technically feasible.

4.1.3 Natural Gas Reburn

Natural gas reburn in the Boardman Plant boiler is not technically feasible because of a lack of sufficient furnace height (i.e., inadequate residence time for NO_x reduction) and because of the lack of installations on boilers in the same size range as the boiler at the Boardman Plant..

4.1.4 SNCR/SCR Hybrid

As described in Subsection 3.1.7, the SCR catalyst reaction occurs within the temperature range of 600 to 750° F. As such, the catalyst must be located after the convective pass of the boiler but before the air preheater. For the Boardman Plant, the temperature of the hot combustion gases exiting the boiler before entry to the air preheater is well in excess of 800º F. The Boardman Plant boiler was not designed with space in the ductwork or with an appropriate temperature or velocity profile for a future SCR. Since the SCR catalyst cannot be located in the existing ductwork without significant modifications to the boiler to lower the gas path temperature (and velocity) to the desired range while still maintaining the air temperature exiting the air preheater to the pulverizer in order to properly dry the coal and maintain combustion efficiency, the SNCR/SCR hybrid system was considered as not technically feasible.

4.2 Technically Infeasible SO_2 Control Technologies

4.2.1 Dry Flue Gas Desulfurization

Dry FGD using a CDS or similar technology has been applied only to boilers rated up to a maximum of 300 MW. Furthermore, most applications of this technology are typically on circulating fluidized bed boilers and not pulverized coal boilers such as the boiler at the Boardman Plant. Therefore, this technology was considered as not technically feasible.

4.2.2 Furnace/Duct Reagent Injection

Furnace or duct reagent injection is considered as not technically feasible because of the lack of installations on boilers in the same size range as the boiler at the Boardman Plant.

4.3 Technically Infeasible PM Control Technologies

4.3.1 GE MAX-9 Hybrid

Current demonstrated GE MAX-9 Hybrid installations are in power boilers that are much smaller than that at the Boardman Plant. Therefore, this technology was considered as not technically feasible.

4.3.2 Multiple-Cyclone Collector

Because of the lower efficiency of multiple-cyclone collectors in reducing PM emissions, this technology is not capable of controlling PM emissions better than the currently existing ESP. Therefore, this technology was not considered further in the analysis.

4.4 Technically Infeasible Emerging Pollution Control Technologies

4.4.1 PowerSpan

As discussed in Subsection 3.4.1, the PowerSpan ECO technology has not been pilot tested in a low-sulfur coal burning facility or in a facility similar in size to the Boardman Plant. Therefore, the PowerSpan ECO system was not considered as technically feasible.

4.4.2 Enviroscrub

The Enviroscrub technology is currently in pilot-scale testing, and there are no current developments in full-scale implementation. Therefore, the Enviroscrub technology is not technically feasible for retrofit at the Boardman Plant.

4.4.3 Phenix CCS

The Phenix CCS technology does not have a commercial-scale installation in a boiler similar in size to the one at the Boardman Plant. Therefore, this technology was not considered technically feasible for application at the Boardman Plant.

4.4.4 J-Power ReACT System

The J-Power ReACT system has only undergone slipstream testing in a North American plant. Therefore, this technology was not considered technically feasible for application at the Boardman Plant.

4.5 Summary of Retrofit Emission Control Technologies Technical Feasibility

A summary of the feasibility evaluation process is detailed in Tables 4-1 to 4-4. Also included in the tables are the reasons for the technical infeasibility of the eliminated control technologies.

Note that Table 4.1 shows new LNBs and MOFA, with either SCR or SNCR. Since PGE is planning to install NLNB/MOFA on the Boardman Plant boiler, and these technologies were the basis for the existing BART NO_x limits which PGE is not requesting be modified, SCR and SNCR are evaluated as additional control technologies.

Table 4-1
Technically Feasible NO_x Control Technologies

Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
Existing OFA system operation	Yes	--
Upgraded LNBs	Yes	--
Upgraded LNBs with existing OFA system operation	Yes	--
Upgraded LNBs with existing OFA system operation and SNCR	Yes	--
New LNBs and modified OFA system	Yes	--
New LNBs with modified OFA system and SNCR	Yes	--
New LNBs with modified OFA system and SCR	Yes	--
SNCR	Yes	--
SNCR/SCR hybrid (Cascade)	No	Not technically feasible to install catalyst within existing ductwork.
Mobotec ROFA and ROTAMIX	No	ROTAMIX not demonstrated on Boardman sized boilers. ROFA system is in the same category as OFA system.
NO_xStar and NO_xStar Plus	No	No existing installation at similar type/size source.
ECOTUBE	No	No existing installation at similar type/size source.
Induced flue gas recirculation (IFGR)	No	Applicable to low nitrogen content fuel fired boilers only.
LoTOx	No	Not commercially available.
Natural Gas Reburn	No	No existing installation at similar type/size source.

Table 4-2
Technically Feasible SO_2 Control Technologies

Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
Wet FGD	Yes	--
Semi-Dry FGD (SDA/FF)	Yes	--
Dry FGD (CDS)	No	No installation at unit larger than 300 MW.
Furnace/Duct Reagent Injection	No	No existing installation at similar type/size source.
Reduced Sulfur Coal Restriction	Yes	Technically feasible at levels of 0.60 lb/MMBtu or greater (as emitted—annual average) after June 30, 2014

Table 4-3
Technically Feasible PM Control Technologies

Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
PJFF	Yes	--
COHPAC	Yes	--
GE MAX-9 Hybrid	No	No commercial installation at similar sized source.
Multiple-cyclone collector	No	Level of emissions control is less effective than currently existing ESP.
WESP	Yes	--

Table 4-4
Technically Feasible Emerging Pollution Control Technologies

Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
PowerSpan	No	No commercial installation at similar sized source.
Enviroscrub	No	No commercial installation at similar sized source.
Phenix Clean Coal	No	No commercial installation at similar sized source.
J-Power ReACT	No	Has only been slipstream tested for evaluation before commercial installations in North America.

5.0 Evaluation of Technically Feasible Retrofit Emission Control Technologies (Step 3)

Step 3 of the BART/Reasonable Progress determination process was an evaluation of all the technically feasible control technologies for control effectiveness so that they could be ranked.

5.1 Control Effectiveness

The evaluation process in Step 3 determined the control effectiveness of each control technology. The control effectiveness was expressed in a common metric based on the amount of pollutant generated per unit of heat input (lb/MMBtu). This evaluation of the control effectiveness was then translated into a yearly rate (ton/yr) for each pollutant according to the highest rolling 12 month data for heat input in the 2003 to 2005 period. The highest rolling 12 month data for heat input are summarized in Table 5-1. The control effectiveness was evaluated according to the sources of information indicated in Subsection 1.2.3.

Table 5-1
Highest Rolling 12 Month Data for Heat Input

Pollutant	Data Period Ending	Heat Input (MMBtu/yr)
NO_x	September 2003	48,630,688
SO_2	August 2005	48,571,330
PM	March 2004	49,093,487

Tables 5-2 to 5-4 identify the baseline emissions and the control effectiveness for each control technology. The tables show the control technology rankings from baseline to the most effective control. The control effectiveness for each technology is also summarized in the Design Concept Definition sheets in Appendix C.

Table 5-2
NO_x Technologies Control Effectiveness

Control Technology	Control Effectiveness (at stack) lb/MMBtu	Control Effectiveness (at stack) tons/yr
Permit Limit	0.70	11,672
BART Baseline	0.43	10,349
Existing OFA system operation	0.40	9,726
Upgraded LNBs	0.38	9,240
SNCR	0.32	7,781
Upgraded LNBs with existing OFA system operation	0.32	7,781
Upgraded LNBs with existing OFA system operation and SNCR	0.24	5,776
Since New LNBs/MOFA is acknowledged as the BART NO_x control technology, no further assessment of the above NO_x control technologies with NO_x emissions higher than 0.23 lb/MMBtu is included in the analysis.		
New LNBs/MOFA	0.23	5,593
New LNBs/MOFA/SNCR	0.19	4,620
New LNBs/MOFA/SCR	0.07	1,702

Table 5-3
SO_2 Technologies Control Effectiveness

Control Technology	Control Effectiveness (at stack) lb/MMBtu	Control Effectiveness (at stack) tons/yr
Permit Limit	1.2	30,449
BART Baseline	0.61	14,814
Reduced Sulfur Coal Restriction	0.60	14,571
Semi-Dry FGD	0.12	2,914
Wet FGD	0.07	1,700

Table 5-4
PM Technologies Control Effectiveness

Control Technology	Control Effectiveness (at stack)[1] lb/MMBtu	Control Effectiveness (at stack)[1] tons/yr
Permit Limit	0.040	1,015
BART Baseline	0.017	417
PJFF	0.012	295
COHPAC	0.012	295
WESP	0.012	295

[1]Particulate data are filterable values determined by US EPA Method 5.

6.0 Impact Analyses (Step 4)

6.1 Types of Impact Analyses

For all the technologies considered, impact analyses were performed as part of the BART/Reasonable Progress determination process. The purpose of these analyses was to identify factors other than control effectiveness that could affect the choice of the best retrofit technology. The following five types of impact analyses were performed in evaluating BART technologies:

- Costs of compliance.
- Energy impacts.
- Non-air quality environmental impacts.
- Existing control technologies.
- Remaining useful life.

The following five types of impact analyses were performed in evaluating Reasonable Progress technologies:

- Costs of compliance.
- Time necessary for compliance.
- Energy impacts.
- Non-air quality environmental impacts.
- Remaining useful life.

6.2 Methods of Impact Analyses

The first step in performing the impact analyses was to define the design parameters for each control technology that was identified as technically feasible. The design parameters contain all pertinent information on the control technology system for specific application to the source. Examples of these design parameters include: type of reagent used and consumption rate, type of byproduct produced and production rate, flue gas pressure drop across the control technology, etc. The information used to define the design parameters included the following:

- Information from equipment vendors.
- Background information documents used to support New Source Performance Standards development.
- Control technique guidelines document.
- EPA cost manuals.
- Trade publications.
- Engineering and performance test data.

The design parameters for each control technology that has been identified as technically feasible for application at the Boardman Plant site are summarized in the Design Concept Definition sheets, which can be found in Appendix C.

6.2.1 Costs of Compliance

The costs of compliance were identified for implementing each technically feasible control technology. The total capital investment for each control technology when applied specifically to the Boardman Plant site and the annual operating and maintenance costs were calculated. These cost calculations were based on the following:

- CUECost Workbook, Version 1.0.
- EPA *Air Pollution Control Cost Manual* - Sixth Edition.
- Budgetary quotes from equipment vendors.
- Quotes or cost estimation for previous design/build projects or in-house engineering estimates.

6.2.2 Energy Impacts

Energy impacts are estimated for each control technology that has consumption of auxiliary energy during its operation. Only direct energy impacts for each control technology, such as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path, are accounted for. Indirect energy impacts, such as the energy to produce raw materials used for the control technology system, are not considered. The auxiliary power consumption estimates for each control technology are based on the typical power consumption of similar equipment of an equivalent size. The additional draft system power consumption calculations are based on the volumetric flow rate of the flue gas through the control technology systems and the flue gas pressure drops defined in the design parameter of each control technology.

For NO_x emissions, SCR has materially higher energy impacts compared to SNCR. The use of an SCR creates additional back pressure that the SNCR system does not cause; additional energy consumption is required to overcome the additional system resistance of an SCR.

Between the three top-ranked control technologies for SO_2 emissions, the energy impacts of the wet FGD are significantly higher than those of the semi-dry FGD although both scrubbing technologies impose a material energy penalty (parasitic load). The imposition of a reduced sulfur coal restriction results in no negative energy impacts.

A COHPAC system consumes more auxiliary energy and ID fan power than a fabric filter, a dry ESP, or a wet ESP. Because the COHPAC uses both dry ESP and FF technologies, the flue gas pressure drop for a COHPAC system is higher than for either a FF or a dry ESP. Similarly, since the COHPAC must operate both ESP and FF, its auxiliary energy use is higher than either a dry ESP or FF. In addition, since the COHPAC uses two different types of equipment for PM control, the cost factor used for maintenance labor and materials is higher for a COHPAC system than for a fabric filter or ESP.

6.2.3 Non-Air Quality Environmental Impacts

Non-air quality impacts were evaluated for each of the control technologies. The major non-air quality impacts evaluated were disposal requirements for the byproduct and waste generated by each control technology. Some of the control technologies generate wastes and/or detrimental byproducts, use excessive water, and/or cause unsightly plumes. In addition, certain control technologies require the storage of large quantities of ammonia and result in the emission of ammonia as slip. These control technologies were identified as having negative environmental impacts.

SCR catalysts must be replaced approximately every 3 years, thus creating a potentially hazardous waste stream, and SCRs require the storage and emission of significant quantities of anhydrous ammonia (the SNCR system is designed for use of urea and less storage is required because of the differences in system use).

Both an SNCR and an SCR system will have ammonia slip. Although SNCR systems typically inject urea, ammonia is produced in the hot injection environment. The majority of the ammonia slip will be collected with the fly ash, and may impact the fly ash quality. Any ammonia slip not collected with the fly ash will negatively impact visibility. In Appendix D to the 2009 Oregon Regional Haze Plan, DEQ rejected SNCR as an emission control technology due to reagent storage and handling safety concerns, the ammonia slip, and the additional water required to keep the boiler system free of slag (App. D; p. D-29). Similar concerns were expressed in relation to SCR, in addition to concerns regarding ammonium bisulfate formation that could damage the air preheater and the impacts associated with disposal of the spent catalyst. These non-air quality environmental impacts associated with SNCR and SCR are equally of concern today and support rejection of either technology as BART.

Both wet and semi-dry FGD present significant non-air quality environmental impacts. As noted by DEQ in Appendix D to the Regional Haze Plan, the wet FGD has multiple severe non-air quality environmental impacts, including that it generates a visible plume, consumes more water, requires water treatment, generates corrosive exhaust gases, and generates a wastewater stream requiring disposal. The semi-dry FGD technology also presents non-air quality environmental impacts including water consumption in an arid region and the generation of solid byproducts for landfill.

The imposition of a reduced sulfur coal restriction results in no non-air quality environmental impacts as the Boardman Plant is already handling coal and the reduced sulfur coal would be a direct substitution.

6.2.4 Existing Controls

The Boardman Plant has existing controls for NO_x, SO_2 and PM. At the time the Boardman Plant was permitted, the NTEC, working in association with DEQ and the public, established emission control requirements reflective of BACT that were imposed on the plant. These included the use of low NO_x burners for NO_x control, low sulfur coal for SO_2 control and an ESP for PM control. The existence of these controls, which have eliminated tens of thousands of tons of visibility impairing emissions since the plant commenced operation, must be taken into account in evaluating BART controls. As EPA has stated that the Reasonable Progress analysis is intended to take into account SIP requirements, these existing controls as well as those control requirements imposed by BART are considered as the baseline conditions for the Reasonable Progress control analysis.

6.2.5 Remaining Useful Life

The Clean Air Act requires that the remaining useful life of a facility be considered in determining BART and Reasonable Progress. Remaining useful life is most often considered when there is an effect on the annualized costs of the retrofit controls for capital recovery. This occurs when the source has a shorter remaining useful life than the expected service life of the control technology. However, Clean Air Act § 169A identifies “remaining useful life” as a separate factor from “costs of compliance” and so basic rules of statutory interpretation require that remaining useful life not be evaluated solely as an element of the cost of compliance. For this BART/Reasonable Progress analysis, the remaining useful life of the controls was defined as the difference between the installation date for controls and the shutdown date.

Ceasing operation of the Boardman Plant boiler is set as no later than December 31, 2020. Thus, the remaining useful life for all SO_2 post-combustion controls and all PM control systems is 6.5 years. The remaining useful life of NO_x combustion control systems is 9.5 years. The remaining useful life of an SCR system and an SNCR system is 4.5 years and 6.5 years, respectively. The remaining useful life values of the controls are calculated based on the anticipated dates for startup of control equipment and the anticipated shutdown date of the unit. The startup dates for controls and the anticipated shut down date are shown in Table 2-2.

The remaining useful life has a major impact on the annualized costs because the capital recovery for installing the equipment is spread over a small number of years. Aside from the impact on cost of compliance, the long term environmental and visibility benefits from the ceasing operation of the Boardman Plant boiler weigh against the installation of additional post-combustion controls.

6.2.6 Time Necessary for Compliance

The Clean Air Act imposes one additional criterion for determining Reasonable Progress controls that is not present in the BART determination process. When evaluating what constitutes Reasonable Progress controls, Congress chose to also require that DEQ consider the time necessary for compliance. The Clean Air Act imposes a deadline for implementing BART, but does not identify the time necessary for compliance as a criterion that applies for actually choosing BART. By contrast, the time necessary for compliance is expressly stated as a criterion for determining Reasonable Progress. As a result, control technologies that take longer to implement are presumably less appropriate for Reasonable Progress and the time that it takes to install and bring on-line a technology must be evaluated as part of the determination process. This is particularly relevant where, as here, PGE is proposing to accept federally enforceable requirements to implement LNB/MOFA, a reduced sulfur coal restriction and to close the plant by December 31, 2020 if post-combustion controls are not required.

6.3 Cost-Effectiveness

The cost-effectiveness of each control technology is calculated from the cost of compliance and the amount of emissions reduced. The cost-effectiveness is described as the cost of control per amount of emissions removed. The emissions reduced are estimated on an annual basis based on the reduction from baseline emissions. Both the baseline emissions and post-control emissions values are documented in the Design Concept Definition sheets located in Appendix C.

Cost-effectiveness is not evaluated in relation to adoption of a reduced sulfur coal restriction. Reduced sulfur coal is more expensive to purchase, and potentially to transport, than low sulfur coal because there is less of it, it is located in limited seams and demand is high. In addition, the limited availability of reduced sulfur coal introduces a supply risk. However, until a contract is negotiated it is difficult to project actual coal prices. Therefore, the cost-effectiveness associated with the use of a reduced sulfur coal is addressed qualitatively rather than quantitatively.

Two types of cost-effectiveness are calculated during the BART/Reasonable Progress determination: average and incremental cost-effectiveness. The general definition of the two types of cost-effectiveness can be found in Subsection 1.2.4. The cost-effectiveness values are based on 2010 dollars. Cost impact analyses were performed for all the identified technically feasible control technologies. Summaries of the calculated cost impact analyses are presented in Appendix D.

EPA stated that "Although States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types." There is no basis at this time for reaching a different conclusion in relation to Reasonable Progress.

6.4 Impact Analyses Results

Table 6-1 was developed for the impact analyses performed. Additionally, the expected post-control emissions levels are shown. The cost impact data in the summary table was used to produce graphical plots of the total annualized cost versus the expected emissions reduction for all control alternatives identified in the BART/Reasonable Progress analyses (Figures 6-1, 6-2, and 6-3).

From the graphical plots, a "least-cost envelope" for each group of control technologies was identified. Control technologies that lie on this least-cost envelope are "dominant controls" that should be the focus for the BART/Reasonable Progress determination. Dominant controls are the technologies that have the lowest cost for implementation per quantity of pollutant removed. Therefore, these technologies will be the top choice as the best method for emissions reduction, barring any additional factors or considerations.

For all the dominant controls, the incremental cost-effectiveness between a technology and the next most stringent control technology was also calculated. This incremental cost-effectiveness indicates the additional cost to increase the emissions reduction when comparing technologies that have different emissions removal capability.

For NO_x, the evaluation generates the same results as those in DEQ's BART analysis incorporated into the Regional Haze Plan. However, NO_x was also evaluated in relation to Reasonable Progress. In that instance, the NLNB/MOFA would be part of the baseline evaluation. Therefore, the additional costs associated with adding SCR or SNCR to NLNB/MOFA would be evaluated in relation to the additional air quality benefits achieved by adding SCR or SNCR to NLNB/MOFA.

Table 6-1
BART/Reasonable Progress Impact Analysis and Cost-Effectiveness Results

All Feasible Technologies	Emission Performance Level (lb/mmBtu)	Expected Emission Rate (tons/yr)	Expected Emission Reductions (tons/year)	Capital Costs (1,000$)	Total Annualized Cost (1,000$)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Energy Impacts (1,000$)	Non-Air Impacts (1,000$)
NO_x Control Technologies									
Baseline	0.43	10,349	--	--	--	--	--	--	--
New LNBs with Modified OFA System	0.23	5,593	4,863	35,683	5,963	1,226	--	26	--
NLNBs, MOFA, and Selective Non-Catalytic Reduction (SNCR)	0.19	4,620	5,836	50,366	10,401	1,782	4,563	26	--
NLNBs, MOFA, and Selective Catalytic Reduction (SCR)	0.07	1,702	8,754	227,375	62,512	7,141	17,859	934	1
SO_2 Control Technologies									
Baseline SO2	0.61	14,911	--	--	--	--	--	--	--
Reduced Sulfur Coal Restriction	0.60	14,571	340	0	--	--	--	--	--
Semi-Dry FGD (including Fabric Filter)	0.12	2,914	11,997	270,218	67,032	5,587	--	1,621	790
Wet FGD (including Fabric Filter)	0.07	1,700	13,211	417,837	101,828	7,708	28,656	6,610	939
PM Control Technologies									
Blaseline PM	0.017	417	--	--	--	--	--	--	--
Compact Hybrid Particulate Collector (COHPAC)	0.012	295	123	88,310	22,920	186,738	--	1,408	--
Pulse Jet Fabric Filter (PJFF)	0.012	295	123	100,442	23,572	192,050	Not Applicable	1,047	--
Wet ESP	0.012	295	123	196,334	42,999	350,329	Not Applicable	652	--

Notes:

1. All costs are in 2010 US$
2. Incremental costs are based on:
a) NLNB, MOFA, and SNCR incremental cost relative to NLNB, MOFA
b) NLNB, MOFA, and SCR incremental cost relative to NLNB, MOFA, SNCR
c) Wet FGD incremental cost relative to Semi-Dry FGD
3. Non-Air Impacts are costs associated with Non- Air Quality Environmental Impacts including generated wastes or detrimental byproducts, and excess water consumed

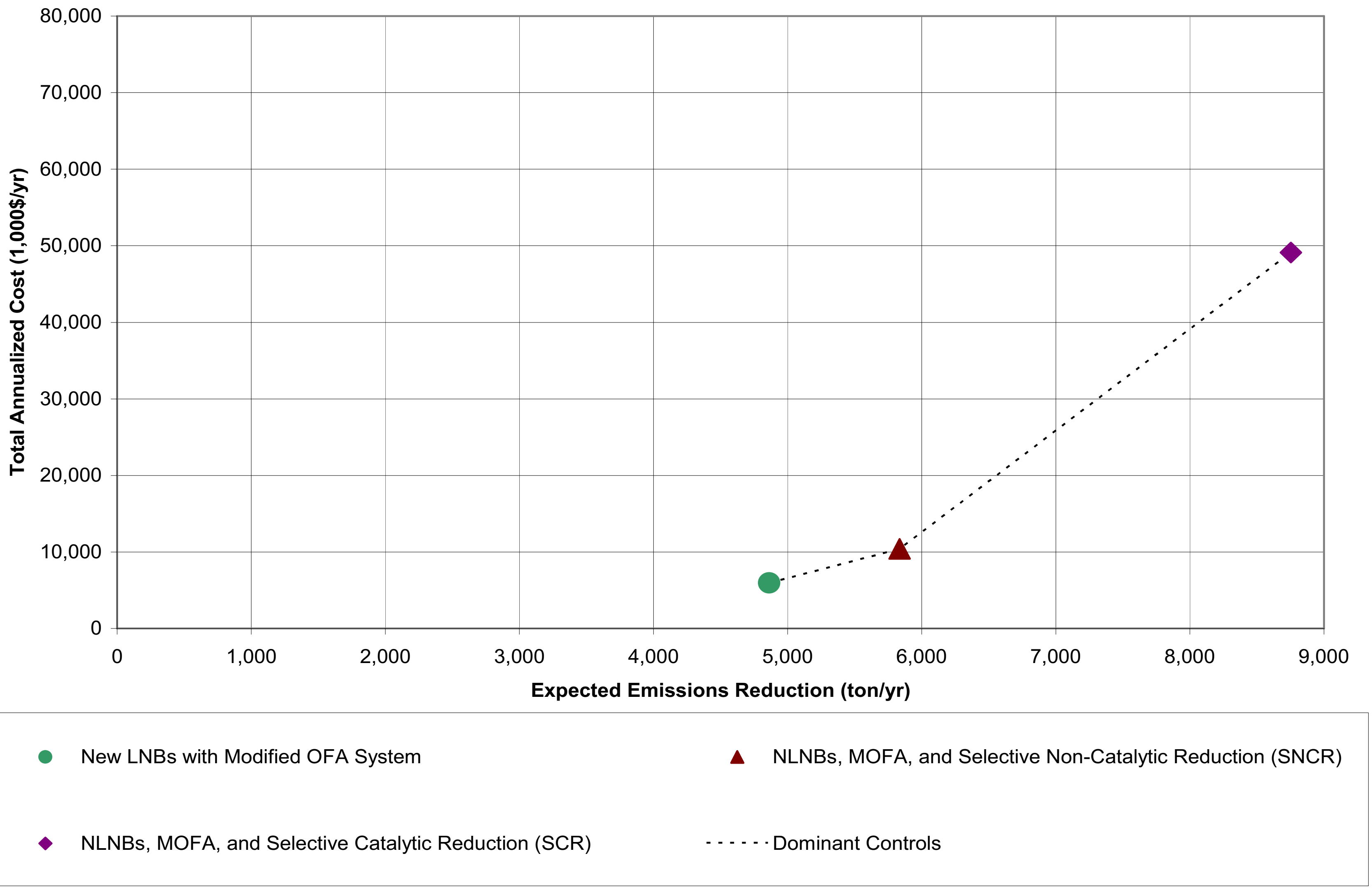

Figure 6-1
NO_x Control Cost-Effectiveness

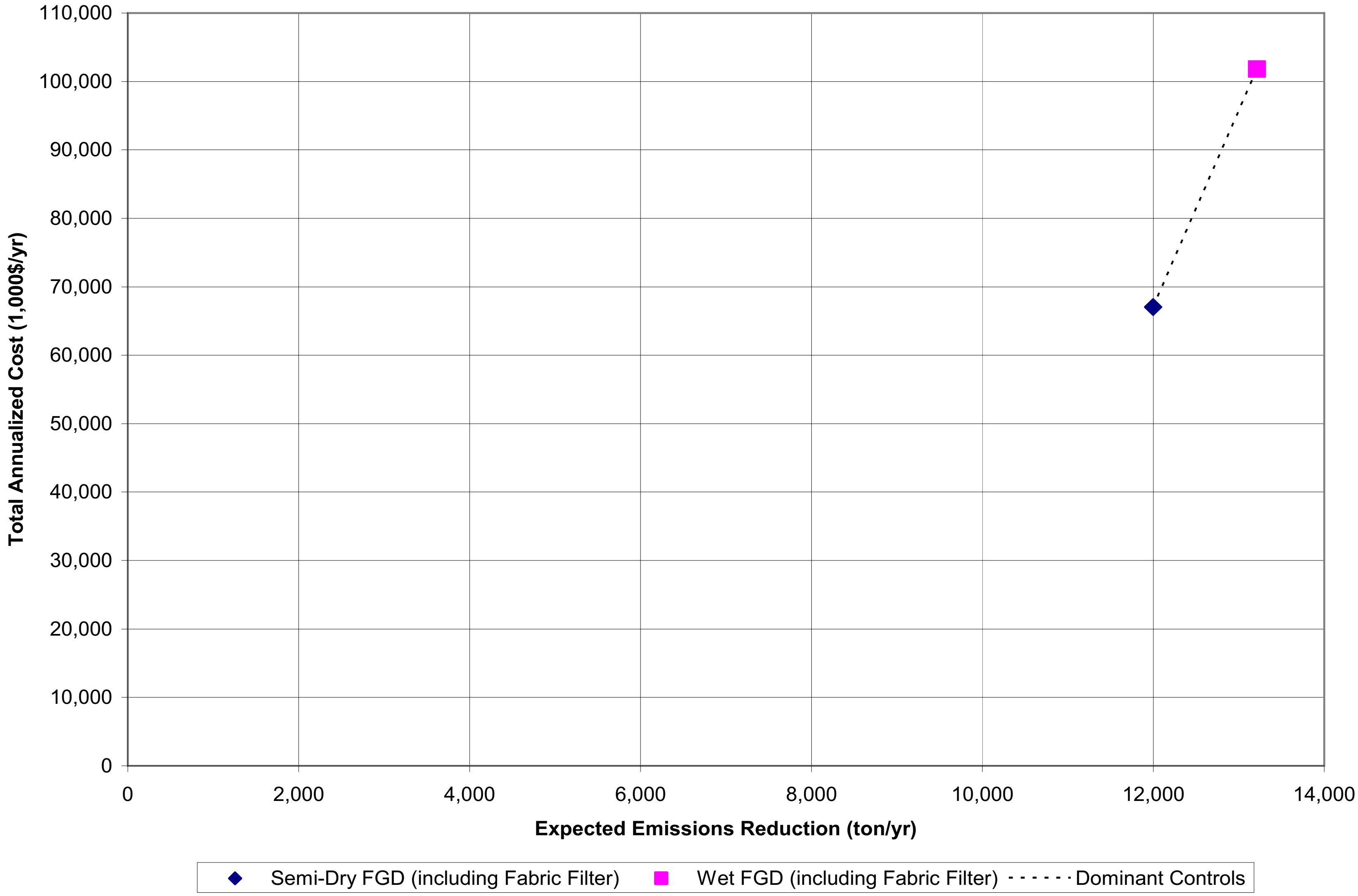

Figure 6-2
SO_2 Control Cost-Effectiveness

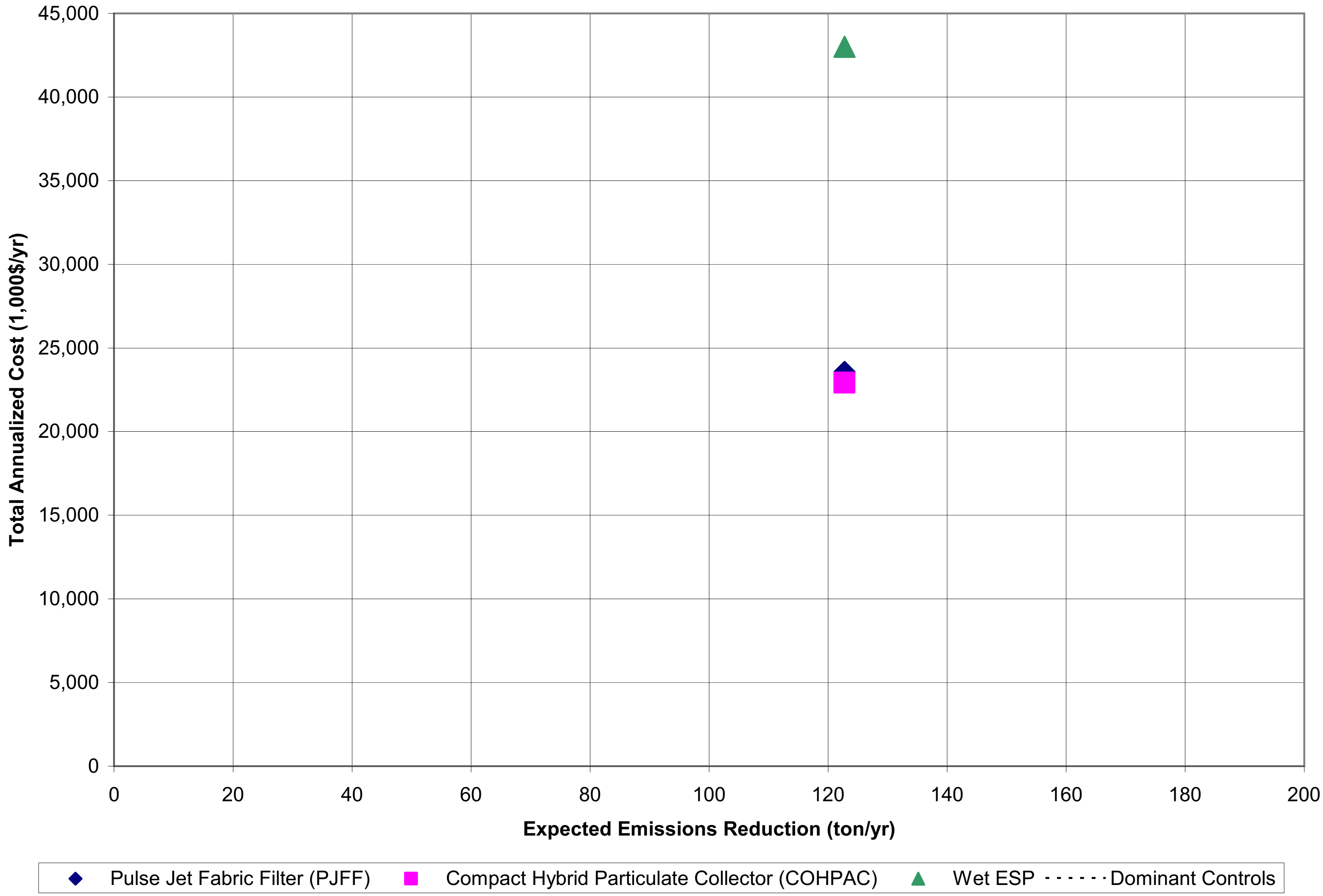

Figure 6-3
PM Control Cost-Effectiveness

For SO_2, the qualitative consideration of reduced sulfur coal generates a very different result from that incorporated into the Regional Haze Plan. With the introduction of an option that reduces the allowable SO_2 emission rate by 50 percent by July 1, 2014, presents no energy or non-air quality impacts, and presents acceptable economic impacts, the analysis for SO_2 BART profoundly changes.

6.4.1 NO_x Control Technologies

In addition to the NLNB/MOFA system being implemented, SNCR and SCR were compared to determine their respective improvement to visibility in the Class I areas. Of the two, the control package utilizing SCR has significantly greater costs of compliance. Both technologies have negative energy impacts and negative non-air quality environmental impacts. Therefore, consistent with the regulations in the current Regional Haze Plan, neither SCR nor SNCR are appropriate as supplements to NLNB/MOFA in establishing BART/Reasonable Progress limits.

6.4.2 SO_2 Control Technologies

Both technically feasible SO_2 post-combustion control technologies as well as the most effective technically feasible SO_2 pre-combustion control technology were evaluated to determine their respective improvement to visibility in the Class I areas. The use of a reduced sulfur coal restriction compares favorably to the post-combustion control technologies. Of the two post-combustion controls, the costs of compliance and the negative non-air quality environmental impacts are greater for the wet FGD control technology. The most effective pre-combustion control technique (reduced sulfur coal restriction of 0.60 lb/MMBtu, as emitted SO_2) presents none of the negative non-air quality environmental impacts presented by the post-combustion controls. Instead, the imposition of a reduced sulfur coal restriction is consistent with the concept of pollution prevention and avoids the potential to shift the pollutant to another media. Both post-combustion control technologies pose high costs of compliance when compared to adoption of a reduced sulfur coal restriction and when considered in relation to the proposed date by which PGE must cease operation of the Boardman Plant boiler. In addition, the remaining useful life of the existing source will be very short if the regulations are modified to impose December 31, 2020 as the date by which PGE must cease operation of the Boardman Plant boiler. In light of such a commitment, the remaining useful life of the Boardman Plant boiler becomes a controlling criterion. The use of reduced sulfur coal (0.60 lb/MMBtu, as emitted SO_2, annual average) should constitute BART for SO_2, particularly if a December 31, 2020 deadline for ceasing operation of the Boardman Plant boiler is added to the rules.

6.4.3 PM Control Technologies

A fabric filter has the least expensive direct annual cost, whereas the COHPAC system has the least expensive capital cost. The total annualized cost for either a COHPAC or a fabric filter system is around $23 million. A wet ESP has significantly higher annualized cost. However, all three technologies pose high costs of compliance when considered in relation to the existing controls and the proposed date by which PGE must cease operation of the Boardman Plant boiler. In addition, the remaining useful life of the existing source will be very short if the regulations are modified to impose December 31, 2020 as the date by which PGE must cease operation of the Boardman Plant boiler. In light of such a commitment, the remaining useful life of the Boardman Plant is too short to justify any of the replacement control technologies and the existing ESP should be the basis for establishing BART/Reasonable Progress limits.

7.0 Visibility Impacts (Step 5)

Evaluation of visibility impacts is the fifth step required under the BART guidelines, but not for the Reasonable Progress process. This step addresses the visibility improvements that would result from installation of the top-ranked technology options identified in the impact evaluation (Step 4). The visibility improvements are represented in terms of the difference between pre-BART controls and the post-BART controls analyses.

Modeling analyses were conducted using CALPUFF (version 6.131). First, emissions associated with pre-BART controls were modeled to establish the baseline for the pre-BART control analyses. Second, individual post-BART control technologies were analyzed for use in selecting final control alternatives.

The methodology used in this analysis was presented in Protocol for the Application of CALPUFF Determination Modeling Pursuant to BART Regulation—PGE Boardman Plant (Revised) (Protocol) (CH2M HILL, 2007). The protocol was initially approved by DEQ on January 18, 2007. As specified in the protocol, all Class I areas within a 300 kilometer (km) radius of the plant were included in the analysis. In addition, although not a Class I area, the Columbia River Gorge National Scenic Area (CRGNSA) was also modeled. However, CRGNSA was modeled for informational purposes only as requested by DEQ. A copy of the protocol and the DEQ approval are provided in Appendix F.

The following sections discuss in greater detail the modeling methodology and results.

7.1 Modeling Methodology

The EPA-approved CALPUFF modeling system was used to assess the visibility impacts as required by the EPA in the BART guideline. CALPUFF is a non-steady-state Lagrangian dispersion model that simulates pollutant releases as a continuous series of "puffs." The Lagrangian dispersion capabilities are coupled with cooperative algorithms for modeling wet and dry deposition, chemical transformation, and plume fumigation. The modeling system is supported by three primary programs:

- CALMET Version 6.211, Level 060414
- CALPUFF Version 6.112, Level 060412
- CALPOST Version 6.131, Level 060410

CALMET is used to create three-dimensional wind fields based on geophysical and meteorological data. The CALMET data used in CALPUFF was provided by DEQ and included meteorological data for 2003, 2004, and 2005. The output of the CALPUFF model consists of binary concentration data files. CALPOST post-processes these data on the basis of specified input parameters that translate pollutant concentration data into visibility impacts.

CALPUFF was run using the control file settings summarized in the modeling protocol. The BART guidelines call for evaluation of the 98th percentile visibility impact in a year or modeling period. The 98th percentile translates to the 8th highest day in a year or the 22nd highest day in the 3-year modeling period. The higher of the 8th and 22nd highs represents the highest visibility impact in terms of magnitude. Additionally, the number of days where the 24hr change in visibility exceeds 0.5 deciview was calculated for each year modeled to address frequency of visibility impacts.

Fourteen Class I areas and the CRGNSA were evaluated. A figure showing the modeling domain covering these areas is included in Appendix F in the modeling protocol. The modeling domain was established to encompass the Boardman Plant and allow for a 50 km buffer around the Class I areas that were within 300 km of the facility. The 14 Class I areas included in the analysis are as follows:

1. Alpine Lakes Wilderness Area.
2. Diamond Peak Wilderness Area.
3. Eagle Cap Wilderness Area.
4. Glacier Peak Wilderness Area.
5. Goat Rocks Wilderness Area.
6. Hells Canyon Wilderness Area.
7. Mount Adams Wilderness Area.
8. Mount Hood Wilderness Area (2009 updated receptors)
9. Mount Jefferson Wilderness Area.
10. Mount Rainer National Park.
11. Mount Washington Wilderness Area.
12. North Cascades National Park.
13. Strawberry Mountain Wilderness Area.
14. Three Sisters Wilderness Area.

An “ozone.dat” file for the 3 year meteorological period was developed by Eri Ottersburg (SLR International) and Mary Beth Yansura (CH2M HILL) with input and review by Oregon DEQ. This file was used in lieu of the default 60 ppb value that was specified in the three state BART Modeling Protocol and the modeling protocol provided in Appendix F. The ozone data incorporated in the file was compiled from state and federal monitors located throughout Washington, Idaho, and Oregon. The ozone.dat file is considered an addition to the protocol and accepted for use in BART modeling. Acceptance of this approach was documented in a memo from Phil Allen of Oregon DEQ to Ray Hendricks of PGE dated August 28, 2007. A copy of the memo is provided in Appendix F.

7.2 Emissions

Table E-1 summarizes the emission rates and stack parameters that were used for the exemption modeling and each BART control scenario. Emission rates and stack parameters have been revised since the January 2007 protocol to reflect 2010 design information. The PM_{10} emissions provided included the front half filterable emissions only. Other particulate species emissions (elemental carbon, fine PM, coarse PM, organic carbon, and inorganic condensables (SO_4)) were calculated in accordance with National Park Service speciation guidelines for dry-bottom pulverized coal boilers[11]. As such, NPS speciation of PM emissions are a function of coal higher heating value, sulfur content, ash content, and boiler heat input rate. These parameters are provided in Appendix A. The result of NPS PM speciation are included with all modeled pollutant species as follows:

- Nitrates (NO_x).
- Sulfur Dioxide (SO_2).
- Nitric Acid (HNO_3) (modeled, not emitted).
- Total PM/PM_{10}:
  - 61.3 % Filterable:
    - 1.0 % Elemental Carbon (EC) (< 2.5 microns [μm]).
    - 26.2% PM Fine (PMF) (< 2.5 μm).
    - 34.1% PM Coarse (PMC) (2.5 – 10 μm).
  - 38.7% PM Condensable:
    - 7.7 % Organic Carbon (OC) (secondary organic aerosol [SOA]).
    - 31.0% Inorganic Aerosol (SO_4).
    - 0.0 % Non-SO_4 Inorganic Aerosol (NO_3).

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[11] http://www.nature.nps.gov/air/permits/ect/ectCoalFiredBoiler.cfm.

7.3 Control Technologies

The six post-control technologies evaluated in Step 4 of the BART process were evaluated in the visibility impact analysis. Individual PM control technologies were not evaluated because of the small contribution PM makes to visibility compared to NO_X and SO_2 in the baseline modeling. The total visibility impact related to PM control technologies for the baseline modeling was less than two percent. Furthermore, SO_2 control technologies include a PJFF system.

The control technologies evaluated include three NO_X controls, three SO_2 controls with PJFF, and one combined NO_X and SO_2 with PJFF control:

- NO_x:
  - New LNBs with modified OFA system and SCR (NLNB/MOFA/SCR).
  - New LNBs with modified OFA system and SNCR (NLNB/MOFA/SNCR).
  - New LNBs with modified OFA system (NLNB/MOFA).
- SO_2 and PM:
  - Wet FGD and PJFF (WFGD/PJFF).
  - Semi-Dry FGD and PJFF (SDFGD/PJFF).
  - Reduced Sulfur Coal Restrictions (RSCR).

7.4 Modeling Results

The tables in this section provide a summary of the visibility impacts and improvements based on modeling results from the different control technology scenarios. A more comprehensive listing of modeling results for each Class I area and the CRGNSA by technology is presented in Appendix E.

Table 7-1 provides a summary of maximum and minimum impacts of all Class I areas modeled for each control scenario in terms of delta deciviews and days where visibility impacts are greater than 0.5 deciviews. Results of the baseline scenario are included in the table for comparison. The RSCR control scenario shows the highest impacts out of all of the post-BART control scenarios. However, the maximum impacts are statistically similar and between 3 to 4 delta-deciviews. A similar distribution is shown for the minimum impacts of each scenario. Additionally, Table 7-1 shows the number of days where the change in visibility exceeds 0.5 delta-deciview. Again, impacts in terms of days for all other scenarios are statistically similar.

Table 7-1
Visibility Impact and Improvement Summary

Impacts in Terms of Δdv (1)						
Scenarios	**Max Impact**	**Max Improvement**		**Min Impact**	**Min Improvement**	
Baseline	5.14	--		1.15	--	
NO_X Controls						
NLNB/MOFA	3.85	1.29	[29.6%]	0.85	0.25	[18.6%]
NLNB/MOFA/SNCR	3.66	1.48	[33.3%]	0.83	0.30	[21.8%]
NLNB/MOFA/SCR	3.25	**1.89**	[42.3%]	0.69	0.44	[29.5%]
SO_2 Controls						
RSCR	**4.64**	0.50	[18.6%]	**1.02**	0.14	[6.6%]
SDFGD/PJFF	3.76	1.38	[48.9%]	0.70	0.42	[24.0%]
WFGD/PJFF	3.91	1.23	**[49.2%]**	0.66	**0.49**	[23.9%]
Impacts in Terms of Days > 0.5 Δdv (2)						
Scenarios	**Max Impact**	**Max Improvement**		**Min Impact**	**Min Improvement**	
Baseline	324	--		60	--	
NO_X Controls						
NLNB/MOFA	239	103	[34.9%]	40	20	[11.5%]
NLNB/MOFA/SNCR	234	111	[42.2%]	37	23	[13.3%]
NLNB/MOFA/SCR	212	**160**	**[61.4%]**	29	31	**[21.5%]**
SO_2 Controls						
RSCR	**278**	46	[23.3%]	**46**	6	[3.3%]
SDFGD/PJFF	235	129	[57.8%]	28	32	[13.0%]
WFGD/PJFF	233	150	**[61.4%]**	26	**34**	[13.7%]

Highest value of all scenarios presented shown in **bold** text.
(1) Based on maximum of annual 8th highest and 3-yr 22nd highest 24-hr impacts from all Class I receptors.
(2) Number of days based on the entire 3-year monitoring period.

Maximum visibility improvements are also provided in Table 7-1 both in terms of deciviews and reduction in days with visibility impacts greater than 0.5 delta-deciviews. The improvement in deciviews represents the best improvement seen in any Class I area when comparing the 98th percentile delta-deciview between the control scenario and baseline. The NLNB/MOFA/SCR and WFGD/PJFF scenarios show the highest maximum and highest minimum visibility improvements.

The baseline model run shows that maximum visibility impacts in terms of frequency occur at Hells Canyon Class I area receptors; in terms of magnitude, maximum impacts occur at Mount Hood. Therefore, frequency and magnitude of impacts are assessed for these two Class I areas and presented in Table 7-2. The NLNB/MOFA/SCR scenario produces the best visibility improvements in terms of frequency at Hells Canyon and magnitude at Mount Hood.

Table 7-2
Hells Canyon and Mount Hood Visibility Improvement Summary

Improvement Over Baseline in Terms of Δdv [(1)] – Mount Hood		
Scenarios	**Maximum Improvement**	
NO_X Controls		
NLNB/MOFA	1.29	[25.0%]
NLNB/MOFA/SNCR	1.48	[28.8%]
NLNB/MOFA/SCR	**1.89**	**[36.8%]**
SO_2 Controls		
RSCR	0.50	[9.7%]
SDFGD/PJFF	1.38	[26.8%]
WFGD/PJFF	1.23	[23.9%]
Improvement Over Baseline in Terms of Days Reduced < 0.5 Δdv [(2)] – Hells Canyon		
Scenarios	**Maximum Improvement**	
NO_X Controls		
NLNB/MOFA	103	[31.8%]
NLNB/MOFA/SNCR	111	[34.3%]
NLNB/MOFA/SCR	**160**	**[49.4%]**
SO_2 Controls		
RSCR	46	[14.2%]
SDFGD/PJFF	129	[39.8%]
WFGD/PJFF	150	[46.3%]

Highest value of all scenarios presented shown in **bold** text.
(1) Based on maximum of annual 8th highest and 3-yr 22nd highest 24-hr impacts from all Class I receptors.
(2) Number of days based on entire 3-year monitoring period.

8.0 Selection of Best Alternative

The CAA and the Guidelines specify that after gathering the data presented in the previous pages of this report, five factors must be applied in order to determine what constitutes BART and four factors must be applied in order to determine Reasonable Progress. The BART factors, identified in CAA Section 169A(g)(2) and codified in 40 C.F.R. § 51.308(e)(1)(ii), are: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts, (3) any existing pollution control technology in use at the source, (4) the remaining useful life, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. The Reasonable Progress factors, identified in CAA Section 169A(g)(1) are: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts, and (4) the remaining useful life.

Consistent with the EPA guidelines and the statutory requirements, PGE completed its BART and Reasonable Progress analyses. The basis for its BART and Reasonable Progress determinations for each of the three BART pollutants is outlined below.

8.1 Selection of PM BART/Reasonable Progress

The three technology options identified in Table 5-4, each offered the same degree of control. All of the options have extremely high cost effectiveness values in excess of $180,000 per ton PM removed. The COHPAC system is the least cost option, however there are several other issues with a COHPAC system that need to be addressed.

The COHPAC system is a less common technology, and limited operating experiences are available. Secondly, the removal of large particulates in the cold-side ESP will result in maintenance concerns. The filter cake, which forms on the surface of the fabric bags, plays an essential role in filtering PM. A filter cake containing both large and small particulates is best. Since the ESP in the COHPAC removes larger particles, the filter cake will consist primarily of smaller particles, which are less effective at filtering PM. Additionally, the filter bags will plug the bag material, since small particulates are more likely to become lodged inside the filter membrane. The requirement for a custom filter bag may mitigate the above mentioned issues, but these custom bags will cost more.

The Boardman Plant's existing controls include a highly efficient dry ESP for PM control. Since the cost effectiveness of any additional control technology is so high, additional PM control technologies cannot be justified as either BART or Reasonable Progress. Therefore, continued use of the existing ESP is considered BART/Reasonable Progress for particulate control.

8.2 Selection of SO_2 BART/Reasonable Progress

Due to the Boardman Plant boiler's short remaining useful life, neither a wet FGD nor a semi-dry FGD could be justified for SO_2 control. The most economical post-combustion control option for SO_2 control is the semi-dry FGD with a capital cost of $270 million and an annual operating cost of $13.8 million. Due to the short Boardman Plant boiler operating life, the annual expense for the semi-dry FGD is over $67 million per year. The other post-combustion control option, a Wet FGD, is significantly more expensive than the semi-dry FGD, resulting in an annual cost of nearly $86 million per year. Neither of these costs are reasonable and therefore excessive economic impacts are a basis for not considering either post-combustion control technology as appropriate for BART or Reasonable Progress. By contrast, the imposition of a reduced sulfur coal limit reducing the allowable SO_2 emissions by 50 percent poses additional fuel costs but at a level acceptable to PGE.

The EPA Guidelines state that it is appropriate to take into account the affordability of particular controls as part of the BART/Reasonable Progress analysis where the cost of installing and operating the controls is judged to have a severe impact on plant operations and plant viability. Since any SO_2 control technology would only be used for 6.5 years due to the Boardman Plant boiler shutdown in 2020, the plant closing is a key consideration in concluding that neither post-combustion control technology is viable. However, because pre-combustion controls involve primarily operating cost and limited capital cost, this technology is not as sensitive to the early shutdown date.

The non-air quality environmental and energy impacts are significant for both post-combustion technologies and nonexistent for the pre-combustion control technology. Both the wet FGD and the semi-dry FGD technologies consume significant amounts of water (around 300 gallons per minute for semi-dry FGD and over 600 gallons/minute for wet FGD). In the arid area of eastern Oregon where the Boardman Plant is located, water is a scarce commodity. A water-intensive process such as these could have an unnecessary impact on the regions existing water resources. Finally, the energy impacts are significant for both technologies, semi-dry FGD using 4,355 kW and a wet FGD consuming 16,249 kW. By contrast, the adoption of a reduced sulfur coal restriction imposes no non-air quality environmental impacts as it relies upon pollution prevention, thereby avoiding the potential to shift impacts to different media. Similarly, the use of reduced sulfur coal is not anticipated to have any energy impacts, in stark contrast to the post-combustion controls.

All three control technologies produce significant improvement in visibility impacts, but the marginal improvement attributable to wet FGD and semi-dry FGD are not sufficient to merit their choice as BART. The visibility modeling demonstrated that both wet and semi-dry FGD result in an approximately 18-20 percent reduction in the number of days at the Mt. Hood Wilderness Area with impacts greater than 1 deciview. Adoption of a reduced sulfur coal restriction would reduce the number of days at the Mt. Hood Wilderness Area with impacts greater than 1 deciview by approximately 7 percent. Therefore, while the visibility improvements attributable to post-combustion controls are greater than those attributable to the imposition of a reduced sulfur coal restriction, the marginal benefits are limited. Were either post-combustion control required as BART or Reasonable Progress, then the Boardman Plant boiler would need to be run beyond the proposed closure date in order to ease the cost recovery schedule. By contrast, if the reduced sulfur coal restriction is imposed as BART then the allowable SO_2 emission rate would drop by half and the visibility impacts on the 98th percentile day would improve by 11 percent (as compared to 27 percent for the semi-dry FGD). The short and long term benefits (e.g., improved visibility, reduced greenhouse gases and criteria pollutants and reduced economic impacts to PGE’s customers) that arise from employing a reduced sulfur coal restriction and imposing a December 31, 2020 deadline for ceasing boiler operation outweigh the benefits from operating the Boardman Plant boiler with an FGD system through the end of the plant’s lifetime.

Based on an analysis of all the statutory factors, it was concluded that the imposition of a reduced sulfur coal limit that ultimately drops the allowable SO_2 emissions by 50 percent (20 percent in 2011 and 50 percent in 2014) and the adoption of a requirement to cease Boardman Plant boiler operation by December 31, 2020 constitutes BART. Neither wet FGD nor semi-dry FGD were viable SO_2 control options for the Boardman Plant. Installation of either technology imposes such significant costs that the plant would potentially need to delay its planned boiler shutdown date of December 31, 2020.[12] In addition, the energy and non-air quality impacts of utilizing either technology are very costly. By contrast, the imposition of a reduced sulfur coal limit at the most restrictive end of the technically feasible range (i.e., 0.60 lb/MMBtu, as

[12] Nothing in the Clean Air Act grants DEQ the authority to require cessation of operation of the Boardman Plant boiler as BART or Reasonable Progress. However, PGE is free to propose an early closure date that is then taken into account in establishing BART and Reasonable Progress controls. If DEQ concludes that either BART or Reasonable Progress requires SCR, FGD or upgraded PM controls, then PGE expressly withdraws consideration of premature closure of the plant as an element in the analysis.

emitted SO_2, annual average) could be implemented by July 1, 2014. Finally, consideration of remaining useful life independent of cost supports the concept that the interference with plant operations and risk of equipment malfunctions is not merited where the boiler will shut down 6.5 years after installation.

The implementation of reduced sulfur coal cannot be accelerated beyond July 1, 2014. No reduction in the SO_2 permit limit can be implemented until the existing coal supply contracts expire at the end of 2011. Once the contracts expire then PGE could begin purchasing reduced sulfur coal to blend with existing coal stockpiles. During the interim period where the Boardman Plant was consuming the stockpiled coal, PGE could accept an SO_2 emission limit of 0.96 lb/MMBtu (annual average). This limit would reduce the allowable SO_2 emission rate by 20 percent two and one half years in advance of the current BART SO_2 limit taking effect. PGE projects that it would take until approximately June 30, 2014 to consume all of the stockpiled coal. After that point, PGE believes that the BART SO_2 limit should be established as 0.60 lb/MMBtu (a 50 percent reduction from the current limit) through closure at the end of 2020.

8.3 Selection of NO_X BART/Reasonable Progress

The application of the statutory factors indicates that, because of the planned NLNB/MOFA system, no additional BART NO_x controls are necessary or justified. DEQ identified multiple reasons in the Regional Haze Plan for why SCR is not an appropriate choice as BART. See, Regional Haze Plan at D-29. PGE does not disagree with the Department's analysis in this regard. SNCR is a possible supplemental control that could be considered BART if the combustion controls are capable of reaching the limits in OAR 340-223-0030(1)(a). However, the environmental impacts associated with this technology support a conclusion that it is not appropriately considered BART. Therefore, this supplemental BART analysis reaches the same conclusion previously reached by DEQ and adopted by the EQC, namely that NLNB/MOFA is BART for the Boardman Plant boiler.

Based on the statutory factors mandated by the Clean Air Act, the Reasonable Progress limit in OAR 340-223-0040 should be replaced with a requirement that PGE cease operations of the Boardman Plant boiler no later than December 31, 2020. The Clean Air Act specifies that the cost of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts, and the remaining useful life of the existing source must be taken into consideration when determining Reasonable Progress. Consistent with the statute, it is appropriate to take into account the economic impact of particular controls in determining Reasonable Progress. The economic impacts associated with SCR are considerable—much higher than the cost of compliance associated with the BART NO_x limits in the Regional Haze Plan. The capital cost of the NLNB/MOFA is estimated as $35.7 million. The capital cost associated with adding SCR to the (then) existing NLNB/MOFA system is approximately $192 million. Operating costs associated with SCR are similarly much higher than the operating costs associated with maintaining the NLNB/MOFA system required by BART. ($6.1 million per year for NLNB/MOFA/SCR as opposed to $0.7 million per year for NLNB/MOFA). As a result, the cost of imposing SCR as Reasonable Progress equates to over $14,500 per ton of NO_x controlled. This is well outside the cost of compliance associated with Reasonable Progress determinations in other states and well outside the range of what is a reasonable cost.

Evaluation of the energy and non-air quality environmental impacts also strongly support the conclusion that SCR is not an appropriate choice for Reasonable Progress. The energy consumption of SCR is 2,509 kW. The high level of SCR energy consumption is a result of the fan auxiliary power needed to overcome additional system resistance. The increased energy consumption results in less electricity being available for distribution to the grid, thus decreasing plant efficiency. The non-air quality environmental impacts associated with the use of either SCR are significant. 364 pounds per hour of anhydrous ammonia are injected into the exhaust for SCR. For a system the size of the Boardman Plant, this results in substantial ammonia slip emissions to the atmosphere which result in significant deposition and visibility impacts. The Department has already indicated that the ammonia slip is a serious concern. The amount of ammonia slip associated with an SCR system of the scale needed for the Boardman Plant results in excessive non-air quality environmental impacts. In addition, if SCR is installed the plant will need to operate beyond December 31, 2020 in order to have a reasonable cost-recovery period. That means that a direct result of a requirement to install SCR is the emission of tens of millions of tons of carbon dioxide. As carbon dioxide is widely considered to contribute to climate change, the climate change impacts directly resulting from a requirement to install SCR must be considered. Therefore, the reduction of greenhouse gas emissions is a considerable nonair quality benefit resulting from not requiring that PGE install SCR to control NO_x.

The remaining useful life of the Boardman Plant also supports the conclusion that Reasonable Progress should not require NO_x limits more stringent than those reflecting combustion controls. Section 169A of the Clean Air Act mandates that DEQ take into account the remaining useful life of the source as a criterion coequal with the other factors (e.g., visibility improvement). The EPA Guidelines suggest accounting for remaining useful life as a component of the cost of compliance. However, Congress expressly identified the remaining useful life of the plant as a criterion distinct and separate from the cost of compliance criterion. Consistent with these statements, DEQ and the EQC have already concluded that SCR is not considered BART. For the same reasons, SCR should not be considered as Reasonable Progress for NO_x if PGE agrees to a fixed date being added to the regulations requiring that PGE cease operation of the Boardman Plant boiler no later than December 31, 2020.

As a result of the excessive economic, energy and non-air quality environmental impacts, as well as consideration of the time necessary for compliance and the remaining useful life of the Boardman Plant, SCR does not constitute Reasonable Progress. PGE proposes that DEQ and the EQC revise the Regional Haze Plan to incorporate regulations mandating that PGE cease operation of the Boardman coal fired boiler no later than December 31, 2020 and remove the Reasonable Progress NO_x limits in OAR 340-223-0040. PGE has no objection to and supports the Department retaining the current BART NO_x limits and deadlines in OAR 340-223-0030.

8.4 Visibility Improvement for Combined BART Controls

As a final step in the evaluation, visibility improvement was evaluated with the combination of controls identified as BART for particulate, SO_2, and NO_x (Table 8-1 and Appendix E). The modeling methodology used for this combination of controls evaluation was the same as the methodology summarized in Section 7.0. This control package includes the reduced sulfur coal restriction and NLNB/MOFA. While these controls are very expensive to install, implement, and operate, they are predicted to result in an average improvement in the plant's modeled visibility impacts across all Class I areas of 39.4 percent and an improvement at the most severely impacted Class I area of 36.6 percent. There would be, on average, only 43 days per year where the impacts would exceed 1.0 deciview, as compared to 90 days per year in the exemption (i.e., baseline) modeling.

While the Columbia River Gorge National Scenic Area (CRGNSA) is not a Class I area and so not a part of the BART analysis, there was interest in the benefits to that area as a result of the proposed BART controls (reduced sulfur coal restriction and NLNB/MOFA). The modeling of the benefits predicted from the proposed BART control package show significant improvement in visibility in the CRGNSA.

Table 8-1 summarizes the modeling results for the combination of reduced sulfur coal restrictions and NLNB/MOFA controls. As shown in Appendix E, the CRGNSA correlates reasonably well with maximum impacts at any Class I area.

Table 8-1 Visibility Impact Summary Boardman Plant BART Determination				
	Reduction in Number of Days Above 0.5 deciview at Highest Frequency Area - Hells Canyon Total (Percent Improvement)			**Reduction in Maximum Visibility Impact at Highset Magnitude Area - Mt Hood deciviews (Percent Improvement)**
Combined Control Technologies	2003	2004	2005	2003-2005[1]
NLNB/MOFA and Reduced Sulfur Coal Restriction **(Best Available Retrofit Technology)**	49 (42.6%)	50 (46.7%)	50 (49.0%)	1.879 (36.6%)

[1]Based on maximum of annual 8th highest and 3-yr 22nd highest 24-hr impacts.
NLNB/MOFA – New Low NO_x Burners with Modified Overfire Air.

9.0 References

(1) CH2M HILL, Protocol for the Application of CALPUFF Determination Modeling Pursuant to BART Regulation—PGE Boardman Plant (Revised), January 2007.

(2) Federal Land Managers' Air Quality Related Values Workgroup (FLAG), *Phase I Report,* December 2000.

(3) Oregon Department of Environmental Quality (DEQ), Modeling Protocol for Washington, Oregon, and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation, October 11, 2006.

(4) US Environmental Protection Agency (EPA), Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts, EPA-454/R-98-019, December 1998.

(5) US Environmental Protection Agency (EPA), *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule*, EPA-454/B-03-005, September 2003.

(6) US Environmental Protection Agency (EPA), *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations*, *Federal Register*, Vol. 70, No. 128, pp. 39104–30172, July 6, 2005.

(7) *Columbia River Gorge Air Quality Study Science Summary Report* (September 24, 2007).

Appendix A
Design Basis

Portland General Electric
Boardman Unit 1
Design Basis Rev. 3
1/14/2010

	Buckskin	Original Design	Black Butte	Worst Case	Range			
	Typical	Low BTU	High BTU	High S Low Btu	Minimum		Maximum	Reference
Coal Quality								
Ultimate Coal analysis (wet basis)								
Carbon (%)	49.01	47.85	55.96		46.90	-	58.51	Provided by PGE
Hydrogen (%)	3.52	3.40	3.70		2.98	-	4.00	Provided by PGE
Sulfur (%)	0.36	0.48	1.00	1.00	0.17	-	1.00	Provided by PGE
Nitrogen (%)	0.69	0.62	1.28		0.35	-	1.37	Provided by PGE
Oxygen (%)	10.87	10.82	9.88		9.67	-	13.20	Provided by PGE
Chlorine (%)	0.01	0.03	0.02		0.00	-	0.06	Provided by PGE
Ash (%)	4.88	6.40	8.00		2.75	-	9.00	Provided by PGE
Moisture (%)	30.66	30.40	20.16		17.30	-	35.65	Provided by PGE
Total (%)	100.00	100.00	100.00					
Higher Heating Value, Btu/lb	8,316	8,020	9,500	8,020	8,020	-	9,800	Provided by PGE
Ash Analysis								
Silica (SiO2)	30.76	31.59	51.53		25.00	-	61.34	Provided by PGE
Alumina (Al2O3)	13.51	15.29	19.68		12.27	-	23.53	Provided by PGE
Iron Oxide (Fe2O3)	5.65	4.55	5.25		2.22	-	8.60	Provided by PGE
Titania (TiO2)	1.03	1.12	0.96		0.36	-	1.42	Provided by PGE
Phosphorous (P2O5)	0.70	0.75	0.80		0.04	-	1.83	Provided by PGE
Lime (CaO)	24.78	22.85	8.28		4.09	-	26.83	Provided by PGE
Magnesia (MgO)	5.71	4.74	2.62		0.54	-	8.80	Provided by PGE
Sodium Oxide (Na2O)	1.59	1.27	2.40		0.65	-	3.37	Provided by PGE
Potassium Oxide (K2O)	0.23	0.44	0.56		0.17	-	1.41	Provided by PGE
Sulfur Trioxide (SO3)	15.10	16.55	7.50		3.00	-	19.80	Provided by PGE
Undetermined	0.96	0.85	0.43		0.43	-	2.50	Provided by PGE
Total (%)	100.00	100.00	100.00					
Unit Characteristics								
Unit Rating, Gross MW	617	617	617					Provided by PGE
Unit Rating, Net Normal Operating, MW	584	584	584					Provided by PGE
Net Turbine Heat Rate, Btu/kWh	7,650	7,650	7,650					Provided by PGE
Net Plant Heat Rate, Btu/kWh (HHV)	9,817	9,841	9,828					B&V Calculated
Boiler Efficiency, %	85.15	84.95	85.06					B&V Combustion Calculations
Boiler Heat Input, MBtu/hr (HHV)	5,736	5,750	5,742	5,793				Provided by PGE
Coal FlowRate, ton/hr	345	358	302					B&V Calculated
Coal FlowRate, lb/hr	689,795	716,947	604,467					B&V Combustion Calculations
Capacity Factor, %	85	85	85					Provided by PGE
Fly Ash Portion of Total Ash, %	80	80	70					Provided by PGE
Air Heater Leakage, %	11.00	11.00	11.00					B&V Combustion Calculations
Boiler Excess Air, %	17.111	17.131	16.545					B&V Combustion Calculations
Boiler Excess Oxygen, %O2 by w.v.	2.79	2.79	2.79					Provided by PGE
Economizer Outlet Conditions								
Flue Gas Temperature, F	807	807	807					Provided by PGE
Flue Gas Pressure, in. w.g.	-5.00	-5.00	-5.00					Provided by PGE
Flue Gas Mass FlowRate, lb/hr	5,879,340	5,957,678	5,748,640					B&V Combustion Calculations
Volumetric Flue Gas FlowRate, acfm	3,264,777	3,307,813	3,154,505					B&V Combustion Calculations
Flue Gas Composition								
Oxygen, % by volume	2.70	2.70	2.70					B&V Combustion Calculations
Carbon Dioxide, % by volume	13.92	13.94	14.34					B&V Combustion Calculations
Moisture, % by volume	13.70	13.74	11.13					B&V Combustion Calculations
Sulfur Dioxide, % by volume	0.04	0.05	0.10					B&V Combustion Calculations
Sulfur Dioxide, acfm	1,251	1,734	3,046					B&V Combustion Calculations
Sulfur Dioxide, ppmv	383	524	966					B&V Calculated
Sulfur Dioxide, lb/hr	4,961	6,876	12,076	14,320				B&V Combustion Calculations
Sulfur Dioxide, lb/MBtu	0.86	1.20	2.10	2.49				B&V Calculated
Particulate Mass Rate, lb/hr	33,865	46,161	50,372					B&V Combustion Calculations
Particulate Concentration, gr/acf	1.210	1.628	1.863					B&V Calculated
Particulate Concentration, lb/MBtu	5.904	8.028	8.772					B&V Calculated
NOx Emissions, lb/MBtu	0.43	0.43	0.43					Provided by PGE, NLNB/ MOFA

Portland General Electric Boardman Unit 1 Design Basis Rev. 3						1/14/2010
Air Heater Outlet Conditions						
Flue Gas Temperature, F	297	297	297			Provided by PGE
Flue Gas Pressure, in. w.g.	-13.00	-13.00	-13.00			Provided by PGE
Flue Gas Mass Flow Rate, lb/hr	6,526,072	6,613,025	6,380,543			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	2,213,484	2,242,692	2,141,130			B&V Combustion Calculations
Flue Gas Composition						
Oxygen, % by volume	4.48	4.48	4.50			B&V Combustion Calculations
Carbon Dioxide, % by volume	12.53	12.54	12.89			B&V Combustion Calculations
Moisture, % by volume	12.54	12.58	10.22			B&V Combustion Calculations
Sulfur Dioxide, % by volume	0.03	0.05	0.09			B&V Combustion Calculations
Sulfur Dioxide, acfm	763	1,058	1,858			B&V Combustion Calculations
Sulfur Dioxide, ppmv	345	472	868			B&V Calculated
Sulfur Dioxide, lb/hr	4,961	6,876	12,076	14,320		B&V Combustion Calculations
Sulfur Dioxide, lb/MBtu	0.86	1.20	2.10	2.49		B&V Calculated
Particulate Mass Rate, lb/hr	33,865	46,161	50,372			B&V Combustion Calculations
Particulate Concentration, gr/acf	1.785	2.401	2.745			B&V Calculated
Particulate Concentration, lb/MBtu	5.904	8.028	8.772			B&V Calculated
NOx Emissions, lb/MBtu	0.43	0.43	0.43			Provided by PGE, NLNB/ MOFA
ID Fan Outlet Conditions						
Flue Gas Temperature, F	293	293	293			Provided by PGE
Flue Gas Pressure, in. w.g.	1.00	1.00	1.00			Provided by PGE
Flue Gas Mass Flow Rate, lb/hr	6,526,072	6,613,025	6,380,543			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	2,123,666	2,151,689	2,054,247			B&V Combustion Calculations
Flue Gas Composition						
Oxygen, % by volume	4.48	4.48	4.50			B&V Combustion Calculations
Carbon Dioxide, % by volume	12.53	12.54	12.89			B&V Combustion Calculations
Moisture, % by volume	12.54	12.58	10.22			B&V Combustion Calculations
Sulfur Dioxide, % by volume	0.03	0.05	0.09			B&V Combustion Calculations
Sulfur Dioxide, acfm	732	1,015	1,783			B&V Combustion Calculations
Sulfur Dioxide, ppmv	345	472	868			B&V Calculated
Sulfur Dioxide, lb/hr	4,961	6,876	12,076	14,320		B&V Combustion Calculations
Sulfur Dioxide, lb/MBtu	0.86	1.20	2.10	2.49		B&V Calculated
Particulate Mass Rate, lb/hr	56	56	56			B&V Calculated
Particulate Concentration, gr/acf	0.003	0.003	0.003			B&V Calculated
Particulate Concentration, lb/MBtu	0.0098	0.0098	0.0098			Provided by PGE
NOx Emissions, lb/MBtu	0.43	0.43	0.43			Provided by PGE, NLNB/ MOFA
Stack Outlet Emissions						
Sulfur Dioxide, lb/MBtu	0.86	1.20	2.10	2.49		
Particulate Concentration, lb/MBtu	0.0098	0.0098	0.0098			Provided by PGE
NOx Emission Rate, lb/MBtu	0.43	0.43	0.43			Provided by PGE, NLNB/ MOFA

Appendix B
Stack Outlet Conditions

Portland General Electric (PGE) - Boardman Unit 1
Best Available Retrofit Technology (BART) Engineering Analysis
Stack Outlet Data for Visibility Modeling

Heat Input (HHV) =	5,793	MBtu/hr (Note 4)								
Stack Outlet Conditions	Flow (acfm)	Stack Velocity (ft/s)	Temperature (°F)	Pressure (in, wg)	SO_2 (lb/MBtu)	SO_2 (lb/hr)	NO_x (lb/MBtu)	NO_x (lb/hr)	PM (lb/MBtu)	PM (lb/hr)
Baseline Case										
1. Existing Operation	2,159,900	95	293	0.50	0.85	4,943	0.54	3,152	0.018	106
NOx Controlled Outlet Conditions										
1. New Low NOx Burners with Modified OFA System and Selective Catalytic Reduction or SCR	2,098,800	92	270	0.50	0.85	4,943	0.07	406	0.018	106
2. New Low NOx Burners with Modified OFA System and SNCR	2,160,500	95	293	0.50	0.85	4,943	0.19	1,101	0.018	106
3. Upgraded Low NOx Burners with Existing OFA System Operation and SNCR	2,161,300	95	293	0.50	0.85	4,943	0.24	1,390	0.018	106
4. New Low NOx Burners with Modified OFA System	2,159,900	95	293	0.50	0.85	4,943	0.23	1,332	0.018	106
5. Upgraded Low NOx Burners with Existing OFA System Operation	2,159,900	95	293	0.50	0.85	4,943	0.32	1,854	0.018	106
6. Selective Non-Catalytic Reduction (SNCR)	2,162,600	95	293	0.50	0.85	4,943	0.32	1,854	0.018	106
7. Upgraded Low NOx Burners	2,159,900	95	293	0.50	0.85	4,943	0.38	2,201	0.018	106
8. Overfire Air System Operation	2,159,900	95	293	0.50	0.85	4,943	0.40	2,317	0.018	106
SO2 Controlled Outlet Conditions										
1. Wet Flue Gas Desulfurization (FGD)	1,823,200	60	136	0.50	0.07	406	0.54	3,152	0.012	70
2. Semi-Dry Flue Gas Desulfurization (FGD)	1,901,700	83	170	0.50	0.12	695	0.54	3,152	0.012	70
3. Reduced Sulfur Coal Restriction	2,159,900	95	293	0.50	0.60	3,476	0.54	3,152	0.018	106
PM Controlled Outlet Conditions										
1. Pulse Jet Fabric Filter (PJFF)	2,159,900	95	293	0.50	0.85	4,943	0.54	3,152	0.012	70
2. Compact Hybrid Particulate Collector (COHPAC)	2,159,900	95	293	0.50	0.85	4,943	0.54	3,152	0.012	70
3. Wet ESP	1,823,200	60	136	0.50	0.85	4,943	0.54	3,152	0.012	70
Composite Controlled Outlet Conditions										
1. New Low NOx Burners with Modified OFA System and Reduced Sulfur Coal Restriction	2,159,900	95	293	0.50	0.60	3,476	0.23	1,332	0.018	106

Notes
1. SO_2 based upon no SO_2 to SO_3 conversion.
2. All PM values based upon front half filterable amounts only.
3. Stack velocity (except for Wet FGD and Wet ESP) based upon existing stack diameter of 22 ft.
4. While 5793 MMBtu/hr is considered the nominal boiler heat input, the maximum boiler heat input is roughly 6400 MMBtu/hr, based on an evaluation of CEMS data from 1997 to 2008 for the maximum 30-day average heat input value of the boiler.

Appendix C
Design Concept Definitions

Design Concept Definition

Site Name	Boardman	**Units**	1	
Client Name	Portland General Electric	**Process Technology**	Overfire Air System Operation	
Process Description	Operate existing overfire air (OFA) system during normal operation. Existing OFA system currently only used when needed to meet permit limit due to efficiency impacts.			
	Pollutant	NO_x		
	Emissions			
	lb/MBtu	0.426		
	ton/yr	10,349		
	Controlled Emissions			
	lb/MBtu	0.40		
	ton/yr	9,727		
	Inlet Flow Basis, acfm	3,307,813		
	Pressure Drop Added	NA		
	Coal Source and Type	Wyoming, Subbituminous		
	Capacity factor	85.0%		
Consumables	Reagent	None		
	Energy	N/A	kW	
	Other	None		
Byproduct	Description	None		
	Other	N/A		

Location of Major Process Equipment	Existing system used sparingly to be operational at all times. Boiler area. Addition of coal flow monitors in coal pipes leading to burner. Addition of water cannon system to boiler wall.
Inlet/Outlet Connections and Interconnecting Ducts	None.
Reagent Storage	None.
Control System Modifications	Addition of NO_x optimization into combustion monitoring process.
Fan Modifications	None.
Power Supply/Aux Power Modifications	No significant aux power impacts from additional equipments.
Enclosures Requirements	None.
Demolition or Relocation Requirements	None.
Major Constructability Issues	None.
Significant Issues or Challenges	Boiler Slagging

Other Assumptions
Coal flow monitors, water cannon system, NO_x optimization and monitoring systems added to overcome boiler slagging issues to allow OFA system operations.
13% reduction expected.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	Equipment is existing at plant but presently not used.

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	Upgraded Low NO_x Burners

Process Description	Low NO_x Burners (LNB) - Upgrade existing. Modifications of burner tips and burner balancing using CFD modeling, combustion air monitoring and coal flow monitoring.		
	Pollutant	NO_x	
	Emissions		
	lb/MBtu	0.426	
	ton/yr	10,349	
	Controlled Emissions		
	lb/MBtu	0.38	
	ton/yr	9,241	
	Inlet Flow Basis, acfm	3,307,813	
	Pressure Drop Added	NA	
	Coal Source and Type	Wyoming, Subbituminous	
	Capacity factor	85.0%	

Consumables	Reagent	None	
	Energy	N/A	kW
	Other	None	
Byproduct	Description	Slight increase in LOI and CO, No impact on ash sales	
	Other	N/A	

Location of Major Process Equipment	Upgrade/additional components to existing burners.
Inlet/Outlet Connections and Interconnecting Ducts	Tie-in to existing air duct and coal pipes.
Reagent Storage	None.
Control System Modifications	None.
Fan Modifications	None.
Power Supply/Aux Power Modifications	None.
Enclosures Requirements	Enclosed already in existing boiler building.
Demolition or Relocation Requirements	None.
Major Constructability Issues	None.
Significant Issues or Challenges	Keep LOI and CO within acceptable levels.

Other Assumptions
No major impact in plant availability.
The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
10% reduction expected.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	Low NO_x Burners already in operation.

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	Upgraded Low NO_x Burners with Existing OFA System Operation

Process Description	Upgrade existing Low NO_x Burners (LNBs) with existing OFA system. Modifications of burner tips and burner balancing.	
	Pollutant	NO_x
	Emissions	
	lb/MBtu	0.426
	ton/yr	10,349
	Controlled Emissions	
	lb/MBtu	0.32
	ton/yr	7,782
	Inlet Flow Basis, acfm	3,307,813
	Pressure Drop Added	NA
	Coal Source and Type	Wyoming, Subbituminous
	Capacity factor	85.0%

Consumables	Reagent	None	
	Energy	N/A	kW
	Other	None	
Byproduct	Description	Slight increase in LOI and CO, No impact on ash sales	
	Other	N/A	

Location of Major Process Equipment	Upgrade existing burners. Location remains the same.
Inlet/Outlet Connections and Interconnecting Ducts	Tie-in to existing air duct and coal pipes.
Reagent Storage	None.
Control System Modifications	None
Fan Modifications	None.
Power Supply/Aux Power Modifications	None
Enclosures Requirements	Enclosed already in existing boiler building.
Demolition or Relocation Requirements	None.
Major Constructability Issues	None.
Significant Issues or Challenges	Keep LOI and CO within acceptable levels.

Other Assumptions
No major impact in plant availability.
The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
40% reduction expected.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	Low NO_x Burners already in operation. Existing OFA system would be placed in operation full time.

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	Selective Non-Catalytic Reduction (SNCR)

Process Description	Selective Non-Catalytic Reduction (SNCR)		
	Pollutant	NO_x	
	Emissions		
	lb/MBtu	0.426	
	ton/yr	10,349	
	Controlled Emissions		
	lb/MBtu	0.32	
	ton/yr	7,782	
	Inlet Flow Basis, acfm	3,307,813	
	Pressure Drop Added	NA	
	Coal Source and Type	Wyoming, Subbituminous	
	Capacity factor	85.0%	
Consumables	Reagent (Urea)	2,170	lb/hr
	Water	533	gpm
	Energy	186	kW
	Maintenance	3% of direct material cost.	
Byproduct	Description	No impact on ash sales.	
	Other	Up to 10 ppm ammonia slip.	

Location of Major Process Equipment	Injection skid and urea tank at grade with truck unloading station.
Inlet/Outlet Connections and Interconnecting Ducts	Install wall injectors and lance-type injectors for SNCR in the boiler.
Reagent Storage	Ammonia tank at grade.
Control System Modifications	Incorporated into existing control system.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Minimum impact/modifications.
Enclosures Requirements	Enclosed in existing boiler building.
Demolition or Relocation Requirements	None.
Major Constructability Issues	None.
Significant Issues or Challenges	Ammonia slip may cause buildup of ammonium bisulfate on the air heater, which may require more frequent cleaning.

Other Assumptions
No major impact in plant availability.
The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
No boiler/duct stiffening included.
Air heater modifications included in analysis.
No impact on potential ash sales.
Reagent is urea.
30% reduction expected.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	--

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	Upgraded Low NO_x Burners with Existing OFA System Operation and SNCR

Process Description	Upgrade existing Low NO_x Burners (LNBs) with existing OFA system. Modifications of burner tips and burner balancing. Selective Non-Catalytic Reduction (SNCR) system for post-combustion reduction of NO_x.		
	Pollutant	NO_x	
	Emissions		
	lb/MBtu	0.32 (Upgraded LNBs + OFA)	
	ton/yr	7782	
	Controlled Emissions		
	lb/MBtu	0.24	
	ton/yr	5,836	
	Inlet Flow Basis, acfm	3,307,813	
	Pressure Drop Added	NA	
	Coal Source and Type	Wyoming, Subbituminous	
	Capacity factor	85.0%	

Consumables	Reagent (Urea)	1630	lb/hr
	Water	400	gpm
	Energy	140	kW
	Maintenance	3% of direct material cost for equipment maintenance.	
Byproduct	Description	Slight increase in LOI and CO, No impact on ash sales	
	Other	Up to 10 ppm ammonia slip.	

Location of Major Process Equipment	Upgrade existing burners. Location remains the same. Injection skid and ammonia tank at grade with truck unloading station.
Inlet/Outlet Connections and Interconnecting Ducts	Tie-in to existing air duct and coal pipes. Install injectors for SNCR in boiler.
Reagent Storage	Ammonia tank for SNCR at grade with injection skid.
Control System Modifications	Control of additional equipment incorporated into current control system.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Minimum impact/modifications.
Enclosures Requirements	Enclosed already in existing boiler building.
Demolition or Relocation Requirements	None.
Major Constructability Issues	None.
Significant Issues or Challenges	Keep LOI and CO within acceptable levels. Ammonia slip may cause buildup of ammonium bisulfate on the air heater, which may require more frequent cleaning.

Other Assumptions
No major impact in plant availability.
The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging.
No boiler/duct stiffening included and no impact on ash sales.
Reagent for SNCR is urea.
Upgraded Low NO_x Burners and OFA system operation reduces reagent consumption for SNCR because of lower NO_x concentration.
50% reduction expected.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	--

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	New Low NO_x Burners with Modified OFA System

Process Description	New low NO_x burners (LNB), modified overfire air (OFA) system. Install new OFA ports at location to be determined during detailed engineering analysis.	
	Pollutant	NO_x
	Emissions	
	lb/MMBtu	0.426
	ton/yr	10,349
	Controlled Emissions	
	lb/MMBtu	0.23
	ton/yr	5,593
	Inlet Flow Basis, acfm	3,307,813
	Pressure Drop Added	NA
	Coal Source and Type	PRB
	Capacity factor	85.0%

Consumables	Reagent	None	
	Energy	N/A	kW
	Other	None	
Byproduct	Description	Slight increase in LOI and CO. No impact on ash sales	
	Other	N/A	

Location of Major Process Equipment	Install new burners in the existing burner openings. Install new OFA ports at location to be determined after analysis.
Inlet/Outlet Connections and Interconnecting Ducts	OFA and burners tie-in to existing air duct and coal pipes.
Reagent Storage	None.
Control System Modifications	Existing control system modification to utilize new equipment.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Minimum impact/modifications.
Enclosures Requirements	Enclosed in existing boiler building.
Demolition or Relocation Requirements	None.
Major Constructability Issues	None.
Significant Issues or Challenges	Keep LOI and CO within acceptable levels.

Other Assumptions

- Water cannon system, NO_x optimization, and monitoring systems added to overcome boiler slagging issues to allow OFA system operations
- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.
- No air heater modifications or boiler/duct stiffening included.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	Replacing older low NO_x burners already in operation and modifying OFA system to support current technology low NO_x burners is common retrofit system.

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	New Low NOx Burners, Modified Overfire Air and Selective Noncatalytic Reduction (SNCR)

Process Description	Selective Noncatalytic Reduction (SNCR) used in conjunction with new low NOx burners and modified overfire air		
	Pollutant	NO_x	
	Emissions		
	lb/MMBtu	0.23 (from NLNB/MOFA)	
	ton/yr	5,593	
	Controlled Emissions		
	lb/MMBtu	0.19	
	ton/yr	4,620	
	Inlet Flow Basis, acfm	3,307,813	
	Pressure Drop Added	NA	
	Coal Source and Type	PRB	
	Capacity factor	85.0%	

Consumables	Reagent (Urea)	815	Lb/hr
	Water	200	gpm
	Energy	70	kW
	Maintenance	3% of direct material cost.	
Byproduct	Description	Minimal impact on ash sales.	
	Other	Up to 10 ppm ammonia slip.	

Location of Major Process Equipment	Injection skid and urea tank at grade with truck unloading station.
Inlet/Outlet Connections and Interconnecting Ducts	Install wall injectors and lance-type injectors for SNCR in the boiler.
Reagent Storage	Storage tank for urea at grade.
Control System Modifications	Incorporated into existing control system.
Fan Modifications	None.
Power Supply/Aux Power Modifications	Minimum impact/modifications.
Enclosures Requirements	Enclosed in existing boiler building.
Demolition or Relocation Requirements	None.
Major Constructability Issues	None.
Significant Issues or Challenges	Ammonia slip may cause buildup of ammonium bisulfate on the air heater, which may require more frequent cleaning.

Other Assumptions

- No major impact in plant availability.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.
- No boiler/duct stiffening included.
- Air heater modifications included in analysis.
- No impact on potential ash sales.
- Reagent used in SNCR process is aqueous urea.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	--

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	New Low NOx Burners, Modified Overfire Air and Selective Catalytic Reduction (SCR)

Process Description	Install a new SCR system in conjunction with new Low NOx Burners and Modified Overfire Air.		
	Pollutant	NO_x	
	Emissions		
	lb/MMBtu	0.23 (from NLNB/MOFA)	
	ton/yr	5,593	
	Controlled Emissions		
	lb/MMBtu	0.07	
	ton/yr	1,702	
	Inlet Flow Basis, acfm	3,307,813	
	Pressure Drop Added	8	
	Coal Source and Type	PRB	
	Capacity factor	85.0%	

Consumables	Reagent (Ammonia)	364	lb/hr
	Energy	2,509	kW
	Catalyst	Add and/or replace one catalyst layer every 3 years.	
	Maintenance	3% of direct material cost.	
Byproduct	Description	Minimal impact on ash sales.	
	Other	5 ppm ammonia slip	

Location of Major Process Equipment	Install SCR reactor above space between the boiler and air heater. Install vaporizers at grade.
Inlet/Outlet Connections and Interconnecting Ducts	SCR inlet and outlet ducts connected into duct entering the air heater.
Reagent Storage	Locate NH3 storage at grade in suitable protective structure or remotely to limit risk from leaks.
Control System Modifications	Existing control system modification to utilize new equipment.
Fan Modifications	Assume booster fans and duct stiffening will be required.
Power Supply/Aux Power Modifications	Assume medium cost expansion will be required for aux electric system.
Enclosures Requirements	Ammonia injection grid area and sonic horns are to be enclosed.
Demolition or Relocation Requirements	Existing economizer outlet ductwork and boiler building wall.
Major Constructability Issues	Finding support steel location under SCR reactor. Tying the SCR into the ductwork downstream of the economizer in the ductwork.
Significant Issues or Challenges	Ammonia slip in the SCR may cause ammonium bisulfate formation on the air heater and require more frequent cleaning. SO_2 to SO_3 conversion by the catalyst, causing pluggage and corrosion in air heater.

Other Assumptions
- No major impact in plant availability.
- Temperature range of flue gas at economizer outlet is acceptable after modifications of boiler superheater section.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.
- Air heater modifications, flue gas handling systems and ammonia handling systems included.
- No boiler/duct stiffening included.
- Modifications made to boiler heat transfer surface area to optimize boiler flue gas outlet temperature for SCR operations.
- No impact on potential ash sales and no additional heating i.e. economizer bypass or duct burners required to achieve operating temperature at low loads.
- Reagent is ammonia and can be anhydrous, aqueous or from urea. Anhydrous ammonia selected as basis.
- SCR reactor includes three initial catalyst layers and one spare layer (3 + 1 arrangement).
- Energy consumption includes ID fan power requirements to overcome SCR system resistance.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	--

Design Concept Definition

Site Name	Boardman		**Units**	1
Client Name	Portland General Electric		**Process Technology**	Wet Flue Gas Desulfurization (FGD) and upstream Fabric Filter
Process Description	Limestone forced oxidation wet flue gas desulfurization process (wet scrubber) with fabric filter upstream of wet scrubber for mercury and particulate control. Description is typical for all absorber/scrubber based FGD systems.			
	Pollutant	SO_2		
	Emissions			
	lb/MMBtu	0.614		
	ton/yr	14,902		
	Controlled Emissions			
	lb/MMBtu	0.07		
	ton/yr	1,700		
	Inlet Flow Basis, acfm	2,151,689		
	Pressure Drop Added (in. wc)	14		
	Coal Source and Type	PRB		
	Capacity factor	85.0%		
Consumables	Reagent (Limestone)	6.244	Tph	
	Water	631.4	Gpm	
	Energy	16,188	kW	
	Maintenance	3% of direct material cost.		
Byproduct	Description	Calcium Sulfite ($CaSO_3 \bullet 1/2H_20$), Calcium Sulfate ($CaSO_4 \bullet 2H_2O$) mixture		
	Production Rate	11.5	Tph	

Location of Major Process Equipment	Fabric filter and wet FGD absorber module flue gas path location is after ID fans and before new wet stack. Reagent preparation and byproduct dewatering equipment to be located around absorber module, location of new wet stack to be determined later.
Inlet/Outlet Connections and Interconnecting Ducts	Connected to ID fan outlet ducts and discharge to the new stack.
Reagent Storage	Silo for reagent will be required.
Control System Modifications	New stand-alone control system, tie in to plant DCS control system.
Fan Modifications	Assume new booster/ID fans and duct stiffening will be required.
Power Supply/Aux Power Modifications	Aux electric system modifications will be required.
Enclosures Requirements	Oxidation air blower building, control building, slaker and slurry tank building, byproduct dewatering building.
Demolition or Relocation Requirements	Abandon existing stack in place.
Major Constructability Issues	Construction of new stack with impacts on restricted safety zone possibly limiting or extending schedule for construction of ductwork, fabric filter system, ID booster fans and wet FGD system.
Significant Issues or Challenges	Tie-in to the current fan ID outlets during a major planned outage.

Other Assumptions

- No modifications to ESP and existing ESP remain in service
- No impact on potential ash sales since existing ESP remains in operation upstream of new AQC equipment.
- One FGD absorber is assumed.
- Fabric filter upstream of wet FGD system is required for mercury and particulate control.
- New wet chimney included.
- No major impact on plant availability is assumed.
- Flue gas handling and ID fan system costs included.
- The FGD byproduct solids would be processed for disposal in a landfill.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	--

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	Semi-Dry Flue Gas Desulfurization (FGD)

Process Description	Semi-dry lime FGD process using the Spray Dryer Absorber (SDA) with downstream Pulse Jet Fabric Filter (PJFF)		
	Pollutant	SO_2	
	Emissions		
	lb/MMBtu	0.614	
	ton/yr	14,902	
	Controlled Emissions		
	lb/MMBtu	0.12	
	ton/yr	2,913	
	Inlet Flow Basis, acfm	2,151,689	
	Pressure Drop Added (in. wc)	12	
	Coal Source and Type	PRB	
	Capacity factor	85.0%	

Consumables	Reagent (Lime)	5.3	tph
	Water	358	gpm
	Energy	4,355	kW
	Maintenance	3% of direct material cost.	
Byproduct	Description	Calcium Sulfite ($CaSO_3 \bullet 1/2H_20$), Calcium Sulfate ($CaSO_4 \bullet 2H_2O$) mixture	
	Production Rate	10.6	tph

Location of Major Process Equipment	Spray Dryer Absorber and Pulse Jet Fabric Filter flue gas flow path location is after ID fans and before stack.
Inlet/Outlet Connections and Interconnecting Ducts	Connected to ID fan outlet ducts and discharge to the existing stack.
Reagent Storage	Silo for reagent will be required.
Control System Modifications	New stand-alone control system, tie in to plant DCS control system.
Fan Modifications	Assume new booster fans and duct stiffening will be required.
Power Supply/Aux Power Modifications	Aux electric system modifications will be required.
Enclosures Requirements	Compressor building, control building, slaker and slurry tank building. Enclose the top pendant areas, the bottom exit and hopper areas of spray dryer and fabric filter.
Demolition or Relocation Requirements	None.
Major Constructability Issues	None.
Significant Issues or Challenges	Tie-in to the current fan ID outlets and stack breaching during a major planned outage.

Other Assumptions

- No modifications to ESP and existing ESP remain in service
- No impact on potential ash sales since existing ESP remains in operation upstream of new AQC equipment.
- Two x 60% FGD absorbers are assumed.
- PJFF provided as integral part of scrubber system also provides particulate control.
- No major impact on plant availability is assumed.
- Flue gas handling system and ID fans upgrades/addition included.
- Lime reagent storage and handling system included.
- Existing chimney is acceptable for resulting flue gas.
- The FGD byproducts solids would be collected in the new fabric filter and would require a separate ash transport system and silo (included).

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	--

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	Reduced Sulfur Coal Restriction

Process Description	A reduced sulfur coal restriction for the Boardman boiler will reduce sulfur dioxide emissions from the current baseline emission rate.		
	Pollutant	SO_2	
	Emissions		
	lb/MMBtu	0.614	
	ton/yr	14,902	
	Controlled Emissions		
	lb/MMBtu	0.6	
	ton/yr	14,562	
	Inlet Flow Basis, acfm	2,151,689	
	Pressure Drop Added (in. wc)	0	
	Coal Source and Type	PRB & other coals that will result in sulfur dioxide emissions below 0.6 lb SO2 / MMBtu	
	Capacity factor	100 %	

Consumables	None
Maintenance	None
Byproduct	None

Location of Major Process Equipment	No new process equipment
Inlet/Outlet Connections and Interconnecting Ducts	No new connections or ductwork
Reagent Storage	N/A
Control System Modifications	None
Fan Modifications	Low sulfur coals may affect fan power due to changes in coal Btu value
Power Supply/Aux Power Modifications	Low sulfur coals may affect auxiliary power due to changes in coal Btu value
Enclosures Requirements	None
Demolition or Relocation Requirements	None
Major Constructability Issues	None
Significant Issues or Challenges	Coal blending is an option that will require effective coal blending, coal accounting, and coal management practices.

Other Assumptions
- No modifications to ESP and existing ESP remain in service
- No impact on potential ash sales
- No major impact on plant availability is assumed.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	--

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	Pulse Jet Fabric Filter (PJFF)

Process Description	Pulse Jet Fabric Filter (PJFF)	
	Pollutant	PM
	Emissions	
	lb/MMBtu	0.0170
	ton/yr	417
	Controlled Emissions	
	lb/MMBtu	0.012
	ton/yr	295
	Inlet Flow Basis, acfm	2,242,692
	Pressure Drop Added (in. wc)	6
	Coal Source and Type	PRB
	Capacity factor	85.0%

Consumables	Reagent	None	
	Energy	3,565	kW
	Maintenance	3% of direct material cost. (Not including bag replacement).	
Byproduct	Description	None.	
	Other	N/A	

Location of Major Process Equipment	Replace existing ESP with new Pulse Jet Fabric Filter (PJFF). Flue gas flow path location will be after air heater outlet and before existing ID fan inlet.
Inlet/Outlet Connections and Interconnecting Ducts	Ductwork connection after air heater outlet and before existing ID fan inlet.
Reagent Storage	None.
Control System Modifications	Incorporated into existing control system.
Fan Modifications	Assume new booster fans or ID fan modifications and duct stiffening will be required.
Power Supply/Aux Power Modifications	Aux electric system modification will be required.
Enclosures Requirements	The top pendent area and bottom hopper area of the fabric filter should be enclosed.
Demolition or Relocation Requirements	None. Existing ESP to be abandoned in place.
Major Constructability Issues	Modification to existing ash handling system.
Significant Issues or Challenges	Installation of new PJFF during a planned major outage.

Other Assumptions

- No major impact in plant availability.
- Collector bag life is 2 years.
- Existing ash disposal system should be capable of servicing the PJFF.
- Flue gas handling and ID fan system upgrades/addition included.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.

State of Availability	Commercial.
Technical Feasibility	Technically feasible and applicable.
Reasons	.

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	Compact Hybrid Particulate Collector (COHPAC)

Process Description	High A/C Ratio Fabric filter, or known as Compact Hybrid Particulate Collector (COHPAC)	
	Pollutant	PM
	Emissions	
	lb/MMBtu	0.0170
	ton/yr	417
	Controlled Emissions	
	lb/MMBtu	0.012
	ton/yr	295
	Inlet Flow Basis, acfm	2,151,689
	Pressure Drop Added (in. wc)	8.0
	Coal Source and Type	PRB
	Capacity factor	85.0%

Consumables	Reagent	None
	Energy	4504 kW
	Maintenance	6% of direct material cost (not including bag costs)
Byproduct	Description	None.
	Other	N/A

Location of Major Process Equipment	COHPAC flue gas path location to be downstream of existing ESP.
Inlet/Outlet Connections and Interconnecting Ducts	Tie-in to flue gas ductwork downstream of existing ESP.
Reagent Storage	None.
Control System Modifications	Incorporated into existing control system.
Fan Modifications	Assume new booster fans and duct stiffening will be required.
Power Supply/Aux Power Modifications	Aux electric system upgrade will be required.
Enclosures Requirements	The top pendant area and the bottom hopper area are enclosed.
Demolition or Relocation Requirements	None.
Major Constructability Issues	None.
Significant Issues or Challenges	Tie-in to the current ID fan outlets during a major planned outage.

Other Assumptions

- No major impact in plant availability.
- Collector bag life is 3 years.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.
- The existing ESP will be left in place upstream of the fabric filter. The fly ash that is collected in the ESP is handled separately and can be sold.
- COHPAC might be used as a component for mercury removal systems.
- Additional ash handling system.

State of Availability	Commercial.
Technical Feasibility	Technically feasible.
Reasons	COHPAC can function as a polishing filter for additional particulate removal and may be used as a component for mercury removal systems.

Design Concept Definition

Site Name	Boardman	**Units**	1
Client Name	Portland General Electric	**Process Technology**	Wet ESP

Process Description	Wet Electrostatic Precipitator (WESP or Wet ESP)		
	Pollutant	PM	
	Emissions		
	lb/MMBtu	0.0170	
	ton/yr	417	
	Controlled Emissions		
	lb/MMBtu	0.012	
	ton/yr	295	
	Inlet Flow Basis, acfm	2,151,689	
	Pressure Drop Added (in. wc)	4.0	
	Coal Source and Type	PRB	
	Capacity factor	85.0%	
Consumables	Reagent ($Mg(OH)_2$)	20	lb/hr
	Water	100	gpm
	Energy	1,752	kW
	Maintenance	3% of direct material cost.	
Byproduct	Description	None.	
	Other	N/A	

Location of Major Process Equipment	Wet ESP flue gas path location to be downstream of existing ESP. Water treatment system to be located next to wet ESP. Additional byproduct disposal system is required.
Inlet/Outlet Connections and Interconnecting Ducts	Tie-in to flue gas ductwork downstream of existing ESP.
Reagent Storage	($Mg(OH)_2$) storage at grade as part of water treatment system.
Control System Modifications	Incorporated into existing control system.
Fan Modifications	Assume new booster fans and duct stiffening will be required.
Power Supply/Aux Power Modifications	Substantial aux electric system modification will be required.
Enclosures Requirements	The top pendant area and the bottom hopper area are enclosed.
Demolition or Relocation Requirements	Abandon existing stack in place.
Major Constructability Issues	Construction of new stack with impacts on restricted safety zone possibly limiting or extending schedule for construction of other control technology equipment.
Significant Issues or Challenges	Tie-in to the current ID fan outlets during a major planned outage.

Other Assumptions

- No major impact in plant availability, however, periodic outages for intense off-line cleanings may be required.
- Aux electric usage is a major factor if using wet ESP as a polishing filter and for SO_3 mitigation.
- The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.
- The existing ESP will be left in place upstream of the WESP. The fly ash that is collected in the ESP is handled separately and can be sold.
- Waste water treatment system included.

State of Availability	Commercial.
Technical Feasibility	Technically feasible.
Reasons	.

Appendix D
Cost Analysis Summary

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: New Low NOx Burners & Modified OFA System **Date:** Jan 14, '10

Cost Item	2010	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
New Low NOx Burners with new secondary air registers	$5,019,000	from vendor quote, 06/30/06			
(8) OFA ports and (4) wing ports with tube throat openings	$2,179,000	from vendor quote, 06/30/06			
Neural network system for NOx optimization	$378,000	B&V cost estimate			
NOx monitoring equipment	$199,000	B&V cost estimate			
Water cannon system	$1,587,000	B&V cost estimate			
Dynamic classifier for coal pulverizers	$1,923,000	B&V cost estimate			
Coal/air flow instrument for burners	$1,022,000	B&V cost estimate			
Modulating orifice for burners	$308,000	B&V cost estimate			
Subtotal capital cost (CC)	$12,615,000				
Freight	$631,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$13,246,000				
Direct installation costs					
Foundation & supports	$0	(PEC) X	0.0%		
Handling & erection	$6,623,000	(PEC) X	50.0%		
Electrical	$1,325,000	(PEC) X	10.0%		
Piping	$662,000	(PEC) X	5.0%		
Insulation	$0	(PEC) X	0.0%		
Painting	$0	(PEC) X	0.0%		
Demolition	$662,000	(PEC) X	5.0%		
Relocation	$662,000	(PEC) X	5.0%		
Total direct installation costs (DIC)	$9,934,000				
Site preparation	$0	N/A			
Buildings	$0	N/A			
Total direct costs (DC) = (PEC) + (DIC)	$23,180,000				
Indirect Costs					
Engineering	$2,782,000	(DC) X	12.0%		
Owner's cost	$464,000	(DC) X	2.0%		
Construction management	$1,159,000	(DC) X	5.0%		
Start-up and spare parts	$464,000	(DC) X	2.0%		
Performance test	$55,000	Engineering estimate			
Contingencies	$4,636,000	(DC) X	20.0%		
Total indirect costs (IC)	$9,560,000				
Allowance for Funds Used During Construction (AFDC)	$2,943,000	[(DC)+(IC)] X	8.99%		2 years (project time /2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$35,683,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$695,000	(DC) X	3.0%		
Total fixed annual costs	$695,000				
Variable annual costs					
N/A	$0	No associated annual cost			
Total variable annual costs	$0				
Total direct annual costs (DAC)	$695,000				
Indirect Annual Costs					
Cost for capital recovery	$5,268,000	(TCI) X	14.8%	CRF at	7.0% interest
Total indirect annual costs (IDAC)	$5,268,000			based on	9.5 year life
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$5,963,000**				

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: Selective Non-Catalytic Reduction (SNCR) **Date:** Jan. 20 2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST	**2010 dollars**					
Direct Costs						
Purchased equipment costs						
Reagent storage, handling, injection & controls	$3,597,241	CUECost estimate				
Initial urea inventory	$180,056	150,000 gal. urea initial inventory				
Air preheater modifications	$3,098,000	CUECost estimate				
Subtotal capital cost (CC)	$6,875,297					
Freight	$413,000	(CC) X	6.0%			
Total purchased equipment cost (PEC)	$7,288,000					
Direct installation costs						
Foundation & supports	$364,000	(PEC) X	5.0%			
Handling & erection	$729,000	(PEC) X	10.0%			
Electrical	$729,000	(PEC) X	10.0%			
Piping	$219,000	(PEC) X	3.0%			
Insulation	$0	(PEC) X	0.0%			
Painting	$0	(PEC) X	0.0%			
Demolition	$146,000	(PEC) X	2.0%			
Relocation	$146,000	(PEC) X	2.0%			
Total direct installation costs (DIC)	$2,333,000					
Site preparation	$0	N/A				
Buildings	$0	N/A				
Total direct costs (DC) = (PEC) + (DIC)	$9,621,000					
Indirect Costs						
Engineering	$1,155,000	(DC) X	12.0%			
Owner's cost	$481,000	(DC) X	5.0%			
Construction management	$962,000	(DC) X	10.0%			
Start-up and spare parts	$289,000	(DC) X	3.0%			
Performance test	$100,000	Engineering estimate				
Contingencies	$1,443,000	(DC) X	15.0%			
Total indirect costs (IC)	$4,430,000					
Allowance for Funds Used During Construction (AFDC)	$632,000	[(DC)+(IC)] X	8.99%	1	year (project length / 2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$14,683,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Operating labor	$100,000		1 FTE and	100,000	$/year	Estimate Labor
Maintenance labor and materials	$289,000	(DC) X	3.0%			
Total fixed annual costs	$389,000					
Variable annual costs						
Reagent	$955,000		815 lb/hr and	315	$/ton	Enginr estim.
Auxiliary and ID fan power	$26,000		70 kW and	0.05	$/kWh	Enginr estim.
Water	$179,000		200 gpm and	2	$/1,000 gal	Enginr estim.
Total variable annual costs	$1,160,000					
Total direct annual costs (DAC)	$1,549,000					
Indirect Annual Costs						
Cost for capital recovery	$2,889,000	(TCI) X	19.67%	CRF at	7%	interest
Total indirect annual costs (IDAC)	$2,889,000			based on	6.5	year life
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$4,438,000**					

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: New Low NOx Burners & Modified OFA System & SNCR **Date:** Jan 20 2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Total Capital Investment (TCI) cost for:						
New Low NOx Burners & Modified OFA System	$35,683,000	Cost estimate for independent system				
Selective Non-Catalytic Reduction System	$14,683,000	Cost estimate for independent system				
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$50,366,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Operating labor	$100,000	1	FTE and	100,000	$/year	Estim. manpower
Maintenance labor and materials	$984,000	(DC) X	3.0%			
Total fixed annual costs	$1,084,000					
Variable annual costs						
Reagent	$955,000	815	lb/hr and	315	$/ton	Engineering estimate
Auxiliary and ID fan power	$26,000	70	kW and	0.05	$/kWh	Engineering estimate
Water	$179,000	200	gpm and	2	$/1,000 gal	Engineering estimate
Total variable annual costs	$1,160,000					
Total direct annual costs (DAC)	$2,244,000					
Indirect Annual Costs						
Cost for capital recovery (NLNB/MOFA)	$5,268,000	(TCI) X	14.76%	CRF at	7%	interest
				based on	9.5	year life
Cost for capital recovery (SNCR)	$2,889,000	(TCI) X	19.67%	CRF at	7%	interest
Total indirect annual costs (IDAC)	$8,157,000			based on	6.5	year life
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$10,401,000**					

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: Selective Catalytic Reduction (SCR) **Date:** 2/23/2010

Cost Item	$	Remarks/Cost Basis					
CAPITAL COST	**2010 dollars**						
Direct Costs							
Purchased equipment costs							
Reactor housing	$6,097,000	CUECost estimate					
Ammonia handling and injection	$1,560,272	CUECost estimate					
Initial catalyst and ammonia	$2,863,414	CUECost estimate					
Electrical system modification	$2,471,000	from ref. cost					
ID fans	$3,997,000	from ref. cost					
Flue gas handling system	$7,103,000	from ref. cost					
Air preheater modifications	$3,098,000	CUECost estimate					
Ash handling system	$3,398,000	CUECost estimate					
Subtotal capital cost (CC)	$30,587,686						
Instruments and controls	$3,059,000	(CC) X	10.0%				
Freight	$1,529,000	(CC) X	5.0%				
Total purchased equipment cost (PEC)	$35,176,000						
Direct installation costs							
Foundation & supports	$13,367,000	(PEC) X	38.0%				
Handling & erection	$13,015,000	(PEC) X	37.0%				
Electrical	$8,794,000	(PEC) X	25.0%				
Piping	$2,638,000	(PEC) X	7.5%				
Insulation	$3,518,000	(PEC) X	10.0%				
Painting	$352,000	(PEC) X	1.0%				
Demolition	$5,980,000	(PEC) X	17.0%				
Relocation	$4,221,000	(PEC) X	12.0%				
Total direct installation costs (DIC)	$51,885,000						
Site preparation	$2,185,000	Engineering estimate					
Buildings	$546,000	Engineering estimate					
Total direct costs (DC) = (PEC) + (DIC)	$89,792,000						
Indirect Costs							
Engineering	$10,775,000	(DC) X	12.0%				
Owner's cost	$4,490,000	(DC) X	5.0%				
Construction management	$8,979,000	(DC) X	10.0%				
Start-up and spare parts	$2,694,000	(DC) X	3.0%				
Performance test	$200,000	Engineering estimate					
Contingencies	$13,469,000	(DC) X	15.0%				
Total indirect costs (IC)	$40,607,000						
Allowance for Funds Used During Construction (AFDC)	$17,584,000	[(DC)+(IC)]	8.99%		3	years (project length / 2)	
Boiler Heat Transfer Surface Area Replacement	$43,709,000	B&V estimate to reduce SCR inlet FG temperature					
Total SCR Capital Investment (TCI)	**$191,692,000**						
ANNUAL COST							
Direct Annual Costs							
Fixed annual costs							
Operating labor	$100,000	1	FTE and		100,000	$/year	Estimated labor
Maintenance labor & materials	$2,694,000	(DC) X	3.0%				
Yearly emissions testing	$27,000	Engineering estimate					
Catalyst activity testing	$5,000	Engineering estimate					
Fly ash sampling and analysis	$22,000	Engineering estimate					
Total fixed annual costs	$2,848,000						
Variable annual costs							
Reagent	$610,000	364	lb/hr and		450	$/ton	Enginr. Estimate
Auxiliary and ID fan power	$934,000	2,509	kW and		0.05	$/kWh	Enginr. Estimate
Catalyst replacement	$1,035,000	173	m3 and		6,000	$/m3	3 yr replacement
Catalyst disposal	$1,000	292,483	lb and		10	$/ton	4 yr replacement
Total variable annual costs	$2,580,000						
Total direct annual costs (DAC)	$5,428,000						
Indirect Annual Costs							
Cost for capital recovery	$51,121,000	(TCI) X	26.67%	CRF at	7%	interest	
Total indirect annual costs (IDAC)	$51,121,000			based on	4.5	year life	
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$56,549,000**						

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: New Low NOx Burners & Modified OFA System & SCR **Date:** Feb 23 2010

Cost Item	$	Remarks/Cost Basis					
CAPITAL COST	**2010 dollars**						
Total Capital Investment (TCI) cost for:							
New Low NOx Burners & Modified OFA System	$35,683,000	Cost estimate for independent system					
Selective Catalytic Reduction System	$191,692,000	Cost estimate for independent system					
Total Capital Investment (TCI)	**$227,375,000**						
ANNUAL COST							
Direct Annual Costs							
Fixed annual costs							
Operating labor	$100,000	1	FTE and	100,000	$/year	Estim. manpower	
Maintenance labor and materials	$3,389,000	(DC) X	3.0%				
Yearly emissions testing	$27,000	Engineering estimate					
Catalyst activity testing	$5,000	Engineering estimate					
Fly ash sampling and analysis	$22,000	Engineering estimate					
Total fixed annual costs	$3,543,000						
Variable annual costs							
Reagent	$610,000	364	lb/hr and	450	$/ton	Engineering estimate	
Auxiliary and ID fan power	$934,000	2509	kW and	0.05	$/kWh	Engineering estimate	
Catalyst replacement	$1,035,000	173	m3 and	6,000	$/m3	3 yr replacement	
Catalyst disposal	$1,000	292,483	lb and	10	$/ton	4 yr replacement	
Total variable annual costs	$2,580,000						
Total direct annual costs (DAC)	$6,123,000						
Indirect Annual Costs							
Cost for capital recovery (NLNB/MOFA)	$5,268,000	(TCI) X	14.76%	CRF at	7%	interest	
				based on	9.5	year life	
Cost for capital recovery (SCR)	$51,121,000	(TCI) X	26.67%	CRF at	7%	interest	
Total indirect annual costs (IDAC)	$56,389,000			based on	4.5	year life	
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$62,512,000**						

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: Wet Flue Gas Desulfurization (FGD) with Fabric Filter **Date:** Jan. 14, 2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs	**2010 dollars**					
Purchased equipment costs						
Reagent feed system: receiving, storage	$1,548,000	CUECost estimate				
Ball mill & classifier	$2,354,000	CUECost estimate				
SO2 removal system: tanks, pumps	$4,212,000	CUECost estimate				
Absorber tower	$33,008,000	CUECost estimate				
Spray pumps	$4,936,000	CUECost estimate				
Byproduct handling system	$1,898,000	CUECost estimate				
Vacuum filter system	$1,803,000	from ref. cost				
Fabric filter with ash handling system	$18,058,000	from ref. cost				
Booster fans	$5,289,000	Engineering estimate				
Electrical system upgrades	$4,639,000	from ref. cost				
Flue gas handling system	$9,616,000	Engineering estimate				
Subtotal capital cost (CC)	$87,361,000					
Instrumentation and controls	$4,368,000	(CC) X	5.0%			
Freight	$4,368,000	(CC) X	5.0%			
Total purchased equipment cost (PEC)	$96,097,000					
Direct installation costs						
Foundation & supports	$26,427,000	(PEC) X	27.5%			
Handling & erection	$38,439,000	(PEC) X	40.0%			
Electrical	$19,219,000	(PEC) X	20.0%			
Piping	$4,805,000	(PEC) X	5.0%			
Insulation	$4,805,000	(PEC) X	5.0%			
Painting	$961,000	(PEC) X	1.0%			
Demolition	$3,844,000	(PEC) X	4.00%			
Relocation	$3,844,000	(PEC) X	4.00%			
Total direct installation costs (DIC)	$102,344,000					
Site preparation	$219,000	Engineering estimate				
Buildings	$8,195,000	Engineering estimate				
New wet stack	$25,133,000	Recent quotes estimate of $23 mil				
Waste water treatment system	$16,391,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$248,379,000					
Indirect Costs						
Engineering	$29,805,000	(DC) X	12.0%			
Owner's cost	$9,935,000	(DC) X	4.0%			
Construction management	$24,838,000	(DC) X	10.0%			
Start-up and spare parts	$3,726,000	(DC) X	1.5%			
Performance test	$219,000	Engineering estimate				
Contingencies	$37,257,000	(DC) X	15.0%			
Total indirect costs (IC)	$105,780,000					
Allowance for Funds Used During Construction (AFDC)	$63,678,000	[(DC)+(IC)	8.99%		4	years (project length / 2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$417,837,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Operating labor	$437,000	4	FTE and	100,000	$/year	Estimated labor
Maintenance labor and materials	$7,451,000	(DC) X	3.0%			
Total fixed annual costs	$7,888,000					
Variable annual costs						
Reagent	$2,427,000	6.484	tph and	46	$/ton	Mass bal. calcs.
Byproduct disposal	$970,000	11.9	tph and	10	$/ton	Mass bal. calcs.
Auxiliary and ID fan power	$6,839,000	16811	kW and	0.05	$/kWh	CueCost calcs
Water	$640,000	655.7	gpm and	2	$/1,000 gal	Mass bal. calcs.
Bag replacement cost	$691,000	6,322	bags and	100	$/bag	18,966 total bags
Cage replacement cost	$173,000	3,161	cages and	50	$/cage	18,966 total cages
Total variable annual costs	$11,740,000					
Total direct annual costs (DAC)	$19,628,000					
Indirect Annual Costs						
Cost for capital recovery	$82,200,000	(TCI) X	19.67%	CRF at	7%	interest
Total indirect annual costs (IDAC)	$82,200,000			based on	6.5	year life
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$101,828,000**					

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: Semi-Dry Flue Gas Desulfurization (FGD) **Date:** Dec 17 2009

Cost Item	$	Remarks/Cost Basis					
CAPITAL COST							
Direct Costs	2010 dollars						
Purchased equipment costs							
Reagent feed: receiving, storage, grinding	$3,646,000	CUECost estimate					
SO2 removal system: tanks, pumps	$3,457,000	CUECost estimate					
Spray dryers and fabric filter	$45,008,000	CUECost estimate					
Ash handling system	$2,185,000	from ref. cost					
Booster fans	$5,289,000	Engineering estimate					
Electrical system upgrades	$3,125,000	from ref. cost					
Flue gas handling system	$9,616,000	CUECost estimate					
Subtotal capital cost (CC)	$72,326,000						
Instrumentation and controls	$1,447,000	(CC) X	2.0%				
Freight	$3,616,000	(CC) X	5.0%				
Total purchased equipment cost (PEC)	$77,389,000						
Direct installation costs							
Foundation & supports	$21,282,000	(PEC) X	27.5%				
Handling & erection	$30,956,000	(PEC) X	40.0%				
Electrical	$15,478,000	(PEC) X	20.0%				
Piping	$3,869,000	(PEC) X	5.0%				
Insulation	$3,869,000	(PEC) X	5.0%				
Painting	$774,000	(PEC) X	1.0%				
Demolition	$3,096,000	(PEC) X	4.0%				
Relocation	$3,096,000	(PEC) X	4.0%				
Total direct installation costs (DIC)	$82,420,000						
Site preparation	$219,000	Engineering estimate					
Buildings	$546,000	Engineering estimate					
Total direct costs (DC) = (PEC) + (DIC)	$160,574,000						
Indirect Costs							
Engineering	$19,269,000	(DC) X	12.0%				
Owner's cost	$6,423,000	(DC) X	4.0%				
Construction management	$16,057,000	(DC) X	10.0%				
Start-up and spare parts	$2,409,000	(DC) X	1.5%				
Performance test	$219,000	Engineering estimate					
Contingencies	$24,086,000	(DC) X	15.0%				
Total indirect costs (IC)	$68,463,000						
Allowance for Funds Used During Construction (AFDC)	$41,181,000	[(DC)+(IC)] X	8.99%		4	years (project length / 2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$270,218,000**						
ANNUAL COST							
Direct Annual Costs							
Fixed annual costs							
Operating labor	$300,000		3	FTE and	100,000	$/year	Estimated labor
Maintenance labor and materials	$4,817,000	(DC) X	3.0%				
Total fixed annual costs	$5,117,000						
Variable annual costs							
Reagent	$5,235,000		5.3	tph and	132	$/ton	Mass bal. calcs.
Byproduct disposal	$790,000		10.6	tph and	10	$/ton	Mass bal. calcs.
Bag replacement cost	$632,000		6,322	bags and	100	$/bag	18,966 total bags
Cage replacement cost	$158,000		3,161	cages and	50	$/cage	18,966 total bags
Auxiliary and ID fan power	$1,621,000		4,355	kW and	0.05	$/kWh	CueCost calcs
Water	$320,000		358	gpm and	2	$/1,000 gal	Mass bal. calcs.
Total variable annual costs	$8,756,000						
Total direct annual costs (DAC)	$13,873,000						
Indirect Annual Costs							
Cost for capital recovery	$53,159,000	(TCI) X	19.67%	CRF at	7%	interest	
Total indirect annual costs (IDAC)	$53,159,000			based on	6.5	year life	
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$67,032,000**						

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: Pulse Jet Fabric Filter (PJFF) **Date:** Dec 21 2009

Cost Item	$	Remarks/Cost Basis
CAPITAL COST		
Direct Costs	**2010 dollars**	
Purchased equipment costs		
Fabric filter system	$18,541,000	CUECost estimate
Initial FF bags inventory		
Ash handling system	$1,322,000	Engineering estimate
Booster fans	$5,938,000	Engineering estimate
Electrical system upgrades	$2,248,000	from ref. cost
Flue gas handling system	$3,967,000	Engineering estimate
Subtotal capital cost (CC)	$32,016,000	
Instrumentation and controls	$1,601,000	(CC) X 5.0%
Freight	$1,601,000	(CC) X 5.0%
Total purchased equipment cost (PEC)	$35,218,000	
Direct installation costs		
Foundation & supports	$10,565,000	(PEC) X 30.0%
Handling & erection	$10,565,000	(PEC) X 30.0%
Electrical	$5,283,000	(PEC) X 15.0%
Piping	$880,000	(PEC) X 2.5%
Insulation	$704,000	(PEC) X 2.0%
Painting	$352,000	(PEC) X 1.0%
Demolition	$1,761,000	(PEC) X 5.00%
Relocation	$352,000	(PEC) X 1.00%
Total direct installation costs (DIC)	$30,462,000	
Site preparation	$164,000	Engineering estimate
Buildings	$0	N/A
Total direct costs (DC) = (PEC) + (DIC)	$65,844,000	
Indirect Costs		
Engineering	$7,231,000	(DC) X 12.0%
Owner's cost	$3,013,000	(DC) X 5.0%
Construction management	$6,026,000	(DC) X 10.0%
Start-up and spare parts	$904,000	(DC) X 1.5%
Performance test	$100,000	Engineering estimate
Contingencies	$9,039,000	(DC) X 15.0%
Total indirect costs (IC)	$26,313,000	
Allowance for Funds Used During Construction (AFDC)	$8,285,000	[(DC)+(IC)] 8.99% 2 years (project time length / 2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$100,442,000**	
ANNUAL COST		
Direct Annual Costs		
Fixed annual costs		
Maintenance labor and materials	$1,975,000	(DC) X 3.0%
Total fixed annual costs	$1,975,000	
Variable annual costs		
Bag replacement cost	$632,000	6,322 bags and 100 $/bag 18,966 total bags
Cage replacement cost	$158,000	3,161 cages and 50 $/cage 18,966 total cages
ID fan power	$841,000	2,258 kW and 0.05 $/kWh 6" water d.p.
Additional Auxiliary power	$206,000	554 kW and 0.05 $/kWh Engineering estimate
Total variable annual costs	$1,837,000	
Total direct annual costs (DAC)	$3,812,000	
Indirect Annual Costs		
Cost for capital recovery	$19,760,000	(TCI) X 19.67% CRF at 7% interest for 6.5 year life
Total indirect annual costs (IDAC)	$19,760,000	
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$23,572,000**	

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: Compact Hybrid Particulate Collector (COHPAC) **Date:** Dec 21 2009

Cost Item	$	Remarks/Cost Basis					
CAPITAL COST							
Direct Costs	**2010 dollars**						
Purchased equipment costs							
Fabric filter system	$13,313,000	from ref. cost					
Initial FF bags inventory							
Ash handling system	$2,404,000	from ref. cost					
Booster fans	$5,481,000	Engineering estimate					
Electrical system upgrades	$2,248,000	from ref. cost					
Flue gas handling system	$7,212,000	Engineering estimate					
Subtotal capital cost (CC)	$30,658,000						
Instrumentation and controls	$1,533,000	(CC) X	5.0%				
Freight	$1,533,000	(CC) X	5.0%				
Total purchased equipment cost (PEC)	$33,724,000						
Direct installation costs							
Foundation & supports	$8,431,000	(PEC) X	25.0%				
Handling & erection	$8,431,000	(PEC) X	25.0%				
Electrical	$4,216,000	(PEC) X	12.5%				
Piping	$843,000	(PEC) X	2.5%				
Insulation	$674,000	(PEC) X	2.0%				
Painting	$337,000	(PEC) X	1.0%				
Demolition	$337,000	(PEC) X	1.00%				
Relocation	$337,000	(PEC) X	1.00%				
Total direct installation costs (DIC)	$23,606,000						
Site preparation	$546,000	Engineering estimate					
Buildings	$0	N/A					
Total direct costs (DC) = (PEC) + (DIC)	$57,876,000						
Indirect Costs							
Engineering	$6,356,000	(DC) X	12.0%				
Owner's cost	$2,648,000	(DC) X	5.0%				
Construction management	$5,297,000	(DC) X	10.0%				
Start-up and spare parts	$795,000	(DC) X	1.5%				
Performance test	$109,000	Engineering estimate					
Contingencies	$7,945,000	(DC) X	15.0%				
Total indirect costs (IC)	$23,150,000						
Allowance for Funds Used During Construction (AFDC)	$7,284,000	[(DC)+(IC)]	8.99%	2	years (project time length X 1/2)		
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$88,310,000**						
ANNUAL COST							
Direct Annual Costs							
Fixed annual costs							
Maintenance labor and materials	$3,473,000	(DC) X	6.0%				
Total fixed annual costs	$3,473,000						
Variable annual costs							
Filter bag replacement	$571,000	5,708	bags and	100	$/bag	11,415 total bags	
Cage replacement	$95,000	1,903	cages and	50	$/cage	11,415 total cages	
ID fan power	$1,076,000	2,889	kW and	0.05	$/kWh	8" water d.p.	
Additional Auxiliary power	$332,000	893	kW and	0.05	$/kWh	Engineering estimate	
Total variable annual costs	$2,074,000						
Total direct annual costs (DAC)	$5,547,000						
Indirect Annual Costs							
Cost for capital recovery	$17,373,000	(TCI) X	19.67%	CRF at 7% interest for 6.5 year life			
Total indirect annual costs (IDAC)	$17,373,000						
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$22,920,000**						

PGE Boardman BART Analysis - Cost Analysis (Draft)

Technology: Wet ESP **Date:** Dec 21 2009

Cost Item	$	Remarks/Cost Basis					
CAPITAL COST							
Direct Costs	**2010 dollars**						
Purchased equipment costs							
WESP system includes casing, electrical sys., penthouse blower & heater, access provisions	$34,139,000	from ref. cost					
Ash handling system	$2,644,000	from ref. cost					
Booster fans	$5,024,000	Engineering estimate					
Electrical system upgrades	$1,454,000	from ref. cost					
Flue gas handling system	$3,967,000	Engineering estimate					
Subtotal capital cost (CC)	$47,228,000						
Instrumentation and controls	$2,361,000	(CC) X	5.0%				
Freight	$2,361,000	(CC) X	5.0%				
Total purchased equipment cost (PEC)	$51,950,000						
Direct installation costs							
Foundation & supports	$15,585,000	(PEC) X	30.0%				
Handling & erection	$15,585,000	(PEC) X	30.0%				
Electrical	$7,793,000	(PEC) X	15.0%				
Piping	$1,299,000	(PEC) X	2.5%				
Insulation	$1,039,000	(PEC) X	2.0%				
Painting	$520,000	(PEC) X	1.0%				
Demolition	$520,000	(PEC) X	1.00%				
Relocation	$520,000	(PEC) X	1.00%				
Total direct installation costs (DIC)	$42,861,000						
Site preparation	$546,000	Engineering estimate					
Buildings	$0	N/A					
New wet stack	$25,133,000	Recent quotes estimate of $23 mil					
Total direct costs (DC) = (PEC) + (DIC)	$120,490,000						
Indirect Costs							
Engineering	$14,459,000	(DC) X	12.0%				
Owner's cost	$6,025,000	(DC) X	5.0%				
Construction management	$12,049,000	(DC) X	10.0%				
Start-up and spare parts	$1,807,000	(DC) X	1.5%				
Performance test	$100,000	Engineering estimate					
Contingencies	$18,074,000	(DC) X	15.0%				
Total indirect costs (IC)	$52,514,000						
Allowance for Funds Used During Construction (AFDC)	$23,330,000	[(DC)+(IC)] X	8.99%		3	years (project length / 2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$196,334,000**						
ANNUAL COST							
Direct Annual Costs							
Fixed annual costs							
Maintenance materials and labor	$2,861,000	(DC) X	3.0%				
Operating labor	$100,000	1	FTE and		100000	$/year	Estimated labor
Total fixed annual costs	$2,961,000						
Variable annual costs							
Reagent	$179,000	20	lb/hr and		1.20	$/ton	Engr. Estimate
Additional Auxiliary power	$130,000	350	kW and		0.05	$/kWh	Engr. Estimate
ID fan power	$522,000	1,402	kW and		0.05	$/kWh	4" water d.p.
Service water	$583,000	652	gpm and		2	$/1,000 gal	Engr. Estimate
Total variable annual costs	$1,414,000						
Total direct annual costs (DAC)	$4,375,000						
Indirect Annual Costs							
Cost for capital recovery	$38,624,000	(TCI) X	19.67%	CRF at 7% interest for 6.5 year life			
Total indirect annual costs (IDAC)	$38,624,000						
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$42,999,000**						

Appendix E
Visibility Modeling Results

Table E-1. Stack Parameters and Modeled Emission Rates
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

	Emission Rates (lb/hr)[1,a]										Stack Parameters[1]			
		SO_X		PM									Exit	Exit
					Filterable				Condensable		Height	Diameter	Velocity	Temperature
Scenario	NO_X	SO_2[2]	SO_4	Total	Total	EC	PMF	PMC	Total	OC	(ft)	(ft)	(ft/s)	(˚F)
Baseline	3,152.00	4,943.10	56.10	176.20	106.10	1.74	45.40	58.90	70.10	14.00	656	22	95	293
New LNB with Modified OFA and SCR	405.51	4,943.10	56.10	176.20	106.10	1.74	45.40	58.90	70.10	14.00	656	22	92	270
New LNB with Modified OFA and SNCR	1,100.67	4,943.10	56.10	176.20	106.10	1.74	45.40	58.90	70.10	14.00	656	22	95	293
New LNB with Modified OFA	1,332.39	4,943.10	56.10	176.20	106.10	1.74	45.40	58.90	70.10	14.00	656	22	95	293
Wet FGD and PJFF	3,152.00	405.51	36.76	115.45	69.52	1.14	29.75	38.59	45.93	9.17	656	25.39	60	136
Semi-Dry FGD and PJFF	3,152.00	695.16	36.76	115.45	69.52	1.14	29.75	38.59	45.93	9.17	656	22	83	170
Reduced Sulfur Coal Restriction	3,152.00	3,475.80	56.10	176.20	106.10	1.74	45.40	58.90	70.10	14.00	656	22	95	293
New LNB with Modified OFA and RSCR	1,332.39	3,475.80	56.10	176.20	106.10	1.74	45.40	58.90	70.10	14.00	656	22	95	293

Calculations:
(a) Emission Rate of PM Species (lb/hr) = [Emission Rate of Total PM (lb/hr]) x [Fraction (%)]

Fraction of Total PM for Dry Bottom Pulverized Coal Boiler with ESP

Filterable PM =	60.2%	(3)
Fine Elemental Carbon (EC) =	1.0%	(3)
Fine Soil (PMF) =	25.8%	(3)
Coarse Particulate (PMC) =	33.4%	(3)
Condensable PM =	39.8%	(3)
Inorganic Aerosol (SO_4) =	31.8%	(3)
Organic Carbon (OC) =	7.9%	(3)

Notes:
(1) Provided by PGE (2010 revised).
(2) SO_2 based on no SO_2 to SO_3 conversion.
(3) From 2007 BART Analysis report (consistent with modeling files provided by Oregon DEQ on February 3, 2010).

LNB = Low NOX Burner, OFA = Overfire Air, SCR = Selective Catalytic Reduction, SNCR = Selective Non-Catalytic Reduction, FGD = Flue Gas Desulfurization, PJFF = Pulse Jet Fabric Filter, RSCR = Reduced Sulfur Coal Restriction

Table E-2. Visibility Analysis Results - Baseline
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

Modeled Area	Delta Deciview: 8th High by Year 2003	2004	2005	22nd High 2003-2005	Maximum Impact	Number of Days >0.5: 2003	2004	2005	Total	Number of Days >1.0: 2003	2004	2005	Total	% of Modeled Extinction by Species: SO_4	NO_3	OC	EC	Location of Maximum (km): X	Y	Date of Maximum
Class I Areas																				
Alpine Lakes	1.749	2.237	2.370	2.237	2.370	40	53	59	152	18	35	38	91	37.010	62.570	0.170	0.050	9.387	-169.701	10/27/2005
Diamond Peak	1.060	1.368	0.593	1.025	1.368	17	31	12	60	10	12	2	24	68.760	30.760	0.200	0.060	-88.497	-579.804	8/14/2004
Eagle Cap	2.225	2.537	1.780	2.225	2.537	100	86	79	265	49	40	33	122	47.940	51.590	0.190	0.060	251.678	-370.249	2/29/2004
Glacier Peak	1.083	1.590	1.621	1.396	1.621	28	40	50	118	8	16	22	46	46.770	52.970	0.110	0.030	12.905	-117.773	1/10/2005
Goat Rocks	1.897	2.533	2.457	2.420	2.533	51	54	52	157	24	34	34	92	49.910	49.660	0.170	0.050	-20.003	-264.534	11/14/2004
Hells Canyon	1.978	1.951	1.780	1.951	1.978	115	107	102	324	50	53	33	136	50.380	48.850	0.320	0.100	321.350	-334.678	5/22/2003
Mt. Adams	1.813	2.760	2.888	2.685	2.888	61	64	60	185	28	39	34	101	29.480	69.960	0.220	0.070	-43.719	-309.142	12/12/2005
Mt. Hood	4.030	5.136	5.026	4.982	5.136	89	95	86	270	68	73	65	206	56.660	42.660	0.270	0.080	-68.798	-390.571	6/22/2004
Mt. Jefferson	3.175	3.349	1.882	3.119	3.349	60	74	54	188	44	48	32	124	49.340	50.080	0.240	0.080	-60.045	-455.736	10/2/2004
Mt. Rainier	1.667	1.988	2.095	2.020	2.095	46	51	48	145	16	27	26	69	42.600	57.020	0.150	0.050	-33.402	-239.419	2/25/2005
Mt. Washington	2.437	2.381	1.618	2.334	2.437	42	61	32	135	28	31	17	76	58.270	41.050	0.260	0.080	-59.214	-501.382	8/8/2003
North Cascades	0.847	1.072	1.151	1.056	1.151	17	27	39	83	3	9	12	24	46.190	53.360	0.180	0.060	-2.674	-60.475	10/5/2005
Strawberry Mountain	1.584	2.238	1.170	1.717	2.238	53	72	47	172	28	35	14	77	50.360	48.970	0.260	0.080	159.632	-496.910	3/2/2004
Three Sisters	2.425	2.422	1.761	2.288	2.425	47	62	28	137	27	32	18	77	57.530	41.780	0.270	0.080	-56.695	-505.881	8/8/2003
Total	**27.970**	**33.562**	**28.192**	**31.455**	**34.126**	**766**	**877**	**748**	**2,391**	**401**	**484**	**380**	**1,265**							
Maximum	**4.030**	**5.136**	**5.026**	**4.982**	**5.136**	**115**	**107**	**102**	**324**	**68**	**73**	**65**	**206**							
Minimum	**0.847**	**1.072**	**0.593**	**1.025**	**1.151**	**17**	**27**	**12**	**60**	**3**	**9**	**2**	**24**							
Average	**1.998**	**2.397**	**2.014**	**2.247**	**2.438**	**55**	**63**	**53**	**171**	**29**	**35**	**27**	**90**							
Class II Areas*																				
Columbia River Gorge	3.034	3.249	4.758	3.709	4.758	92	92	83	267	61	57	56	174	32.420	66.850	0.270	0.080	-12.812	-355.812	2/8/2005

* Class II area modeled for informational purposes.

Table E-3. Visibility Analysis Results - New LNB with Modified OFA and SCR
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

	Delta Deciview													% of Modeled Extinction by Species				Location of Maximum (km)		
	8th High by Year			22nd High	Maximum	Number of Days >0.5				Number of Days >1.0										Date of
Modeled Area	**2003**	**2004**	**2005**	**2003-2005**	**Impact**	**2003**	**2004**	**2005**	**Total**	**2003**	**2004**	**2005**	**Total**	**SO_4**	**NO_3**	**OC**	**EC**	**X**	**Y**	**Maximum**
Class I Areas																				
Alpine Lakes	1.060	1.428	1.367	1.318	1.428	23	37	41	101	9	18	16	43	87.320	12.030	0.270	0.080	22.696	-166.085	12/16/2004
Diamond Peak	0.658	0.931	0.362	0.627	0.931	10	15	4	29	3	6	0	9	90.930	8.260	0.330	0.100	-74.959	-586.249	9/26/2004
Eagle Cap	1.409	1.471	1.027	1.379	1.471	69	50	38	157	21	23	9	53	82.880	16.410	0.280	0.090	246.886	-375.820	12/2/2004
Glacier Peak	0.580	1.081	0.904	0.787	1.081	14	24	27	65	2	8	7	17	86.030	13.340	0.260	0.080	12.905	-117.773	11/8/2004
Goat Rocks	1.104	1.749	1.331	1.379	1.749	33	39	34	106	11	22	15	48	91.840	7.450	0.270	0.080	-27.339	-253.767	12/28/2004
Hells Canyon	1.209	1.242	0.891	1.174	1.242	62	58	44	164	17	16	5	38	96.620	2.750	0.240	0.070	322.788	-338.184	1/27/2004
Mt. Adams	1.062	1.851	1.393	1.564	1.851	40	46	35	121	8	27	13	48	94.740	5.030	0.090	0.030	-35.641	-306.512	11/11/2004
Mt. Hood	2.476	3.248	2.765	2.814	3.248	69	77	66	212	49	50	42	141	93.890	4.730	0.550	0.170	-63.863	-394.481	7/24/2004
Mt. Jefferson	2.134	2.271	1.068	2.076	2.271	47	56	36	139	26	30	12	68	89.000	9.830	0.480	0.150	-60.344	-486.158	6/2/2004
Mt. Rainier	1.020	1.476	1.225	1.334	1.476	25	35	27	87	8	16	12	36	91.600	8.030	0.160	0.050	-66.536	-242.717	1/21/2004
Mt. Washington	1.613	1.497	0.965	1.474	1.613	36	41	19	96	18	20	6	44	88.840	10.460	0.270	0.080	-59.214	-501.382	11/2/2003
North Cascades	0.464	0.690	0.628	0.593	0.690	5	11	16	32	1	6	3	10	86.560	12.850	0.240	0.080	24.653	-58.631	11/8/2004
Strawberry Mountain	0.962	1.291	0.703	0.998	1.291	31	36	19	86	6	13	2	21	88.500	10.360	0.450	0.140	162.190	-496.843	3/2/2004
Three Sisters	1.596	1.561	0.987	1.404	1.596	34	40	20	94	16	18	7	41	90.840	8.080	0.410	0.130	-56.695	-505.881	8/8/2003
Total	**17.347**	**21.787**	**15.616**	**18.921**	**21.938**	**498**	**565**	**426**	**1,489**	**195**	**273**	**149**	**617**							
Maximum	**2.476**	**3.248**	**2.765**	**2.814**	**3.248**	**69**	**77**	**66**	**212**	**49**	**50**	**42**	**141**							
Minimum	**0.464**	**0.690**	**0.362**	**0.593**	**0.690**	**5**	**11**	**4**	**29**	**1**	**6**	**0**	**9**							
Average	**1.239**	**1.556**	**1.115**	**1.352**	**1.567**	**36**	**40**	**30**	**106**	**14**	**20**	**11**	**44**							
Class II Areas*																				
Columbia River Gorge	1.553	2.185	2.504	2.217	2.504	68	67	58	193	31	35	40	106	89.060	9.880	0.410	0.130	-5.312	-355.823	12/19/2005

* Class II area modeled for informational purposes.
LNB = Low NOX Burner, OFA = Overfire Air, SCR = Selective Catalytic Reduction

Table E-4. Visibility Analysis Results - New LNB with Modified OFA and SNCR
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

Modeled Area	Delta Deciview 8th High by Year 2003	2004	2005	22nd High 2003-2005	Maximum Impact	Number of Days >0.5 2003	2004	2005	Total	Number of Days >1.0 2003	2004	2005	Total	% of Modeled Extinction by Species SO_4	NO_3	OC	EC	Location of Maximum (km) X	Y	Date of Maximum
Class I Areas																				
Alpine Lakes	1.278	1.573	1.686	1.484	1.686	29	41	47	117	13	20	25	58	76.380	23.240	0.150	0.050	22.696	-166.085	1/25/2005
Diamond Peak	0.742	1.070	0.402	0.730	1.070	12	21	4	37	5	8	0	13	79.170	20.120	0.290	0.090	-74.959	-586.249	9/26/2004
Eagle Cap	1.572	1.724	1.160	1.528	1.724	74	57	51	182	30	29	15	74	73.350	25.940	0.290	0.090	251.678	-370.249	2/29/2004
Glacier Peak	0.796	1.067	1.081	0.959	1.081	18	28	34	80	3	8	8	19	71.860	27.740	0.170	0.050	12.905	-117.773	1/10/2005
Goat Rocks	1.472	1.883	1.580	1.611	1.883	39	47	41	127	12	27	19	58	81.740	17.620	0.240	0.070	-23.653	-253.783	12/28/2004
Hells Canyon	1.379	1.372	1.133	1.367	1.379	78	66	69	213	24	25	12	61	78.080	20.750	0.470	0.150	335.851	-348.218	5/23/2003
Mt. Adams	1.204	2.181	1.772	1.772	2.181	46	48	44	138	14	29	20	63	83.540	16.130	0.130	0.040	-43.719	-309.142	1/20/2004
Mt. Hood	2.865	3.657	3.341	3.356	3.657	74	86	74	234	55	56	47	158	69.910	29.310	0.300	0.090	-49.716	-407.458	11/10/2004
Mt. Jefferson	2.355	2.392	1.220	2.251	2.392	51	60	41	152	28	37	20	85	77.270	21.590	0.470	0.140	-71.754	-478.876	8/14/2004
Mt. Rainier	1.258	1.458	1.416	1.416	1.458	32	37	32	101	9	21	16	46	79.100	20.560	0.140	0.040	-42.020	-244.733	12/18/2004
Mt. Washington	1.824	1.731	1.187	1.635	1.824	38	46	21	105	21	23	10	54	75.090	24.320	0.230	0.070	-59.214	-501.382	11/2/2003
North Cascades	0.589	0.833	0.770	0.710	0.833	11	15	22	48	1	7	4	12	86.960	12.490	0.230	0.070	24.653	-58.631	9/26/2004
Strawberry Mountain	1.152	1.566	0.805	1.204	1.566	38	47	26	111	11	15	5	31	74.570	24.440	0.390	0.120	159.632	-496.910	3/2/2004
Three Sisters	1.813	1.724	1.263	1.563	1.813	38	47	21	106	20	24	10	54	79.340	19.710	0.370	0.110	-56.695	-505.881	8/8/2003
Total	**20.299**	**24.231**	**18.816**	**21.586**	**24.547**	**578**	**646**	**527**	**1,751**	**246**	**329**	**211**	**786**							
Maximum	**2.865**	**3.657**	**3.341**	**3.356**	**3.657**	**78**	**86**	**74**	**234**	**55**	**56**	**47**	**158**							
Minimum	**0.589**	**0.833**	**0.402**	**0.710**	**0.833**	**11**	**15**	**4**	**37**	**1**	**7**	**0**	**12**							
Average	**1.450**	**1.731**	**1.344**	**1.542**	**1.753**	**41**	**46**	**38**	**125**	**18**	**24**	**15**	**56**							
Class II Areas*																				
Columbia River Gorge	1.916	2.362	3.003	2.641	3.003	75	75	67	217	41	40	45	126	57.870	41.220	0.350	0.110	-50.325	-357.404	2/26/2005

* Class II area modeled for informational purposes.
LNB = Low NOX Burner, OFA = Overfire Air, SNCR = Selective Non-Catalytic Reduction

Table E-5. Visibility Analysis Results - New LNB with Modified OFA
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

	Delta Deciview					Number of Days >0.5				Number of Days >1.0				% of Modeled Extinction by Species				Location of Maximum (km)		Date of Maximum
	8th High by Year			22nd High	Maximum															
Modeled Area	**2003**	**2004**	**2005**	**2003-2005**	**Impact**	**2003**	**2004**	**2005**	**Total**	**2003**	**2004**	**2005**	**Total**	**SO_4**	**NO_3**	**OC**	**EC**	**X**	**Y**	
Class I Areas																				
Alpine Lakes	1.347	1.665	1.763	1.564	1.763	30	44	49	123	13	22	27	62	72.760	26.870	0.140	0.040	22.696	-166.085	1/25/2005
Diamond Peak	0.779	1.114	0.423	0.757	1.114	13	21	6	40	6	8	0	14	75.850	23.470	0.280	0.090	-74.959	-586.249	9/26/2004
Eagle Cap	1.620	1.815	1.232	1.611	1.815	76	61	59	196	33	30	16	79	69.340	29.990	0.270	0.080	251.678	-370.249	2/29/2004
Glacier Peak	0.832	1.129	1.141	1.008	1.141	22	29	39	90	3	8	11	22	67.790	31.830	0.160	0.050	12.905	-117.773	1/10/2005
Goat Rocks	1.521	1.946	1.662	1.702	1.946	43	47	41	131	14	28	20	62	78.840	20.550	0.230	0.070	-23.653	-253.783	12/28/2004
Hells Canyon	1.486	1.438	1.222	1.435	1.486	81	69	71	221	25	28	14	67	48.230	50.230	0.620	0.190	322.494	-379.413	12/26/2003
Mt. Adams	1.242	2.249	1.914	1.899	2.249	48	49	48	145	17	29	22	68	80.790	18.890	0.120	0.040	-43.719	-309.142	1/20/2004
Mt. Hood	3.021	3.850	3.537	3.537	3.850	76	86	77	239	56	57	51	164	65.790	33.480	0.280	0.090	-49.716	-407.458	11/10/2004
Mt. Jefferson	2.442	2.493	1.269	2.355	2.493	52	63	46	161	31	38	21	90	73.780	25.130	0.450	0.140	-71.754	-478.876	8/14/2004
Mt. Rainier	1.343	1.518	1.478	1.478	1.518	32	38	32	102	10	21	19	50	75.740	23.940	0.130	0.040	-42.020	-244.733	12/18/2004
Mt. Washington	1.906	1.804	1.222	1.711	1.906	38	47	22	107	21	24	11	56	81.190	18.110	0.290	0.090	-59.214	-501.382	8/13/2003
North Cascades	0.617	0.846	0.804	0.747	0.846	11	19	24	54	1	7	5	13	84.720	14.750	0.230	0.070	24.653	-58.631	9/26/2004
Strawberry Mountain	1.175	1.644	0.839	1.281	1.644	40	50	29	119	11	19	5	35	70.800	28.270	0.370	0.110	159.632	-496.910	3/2/2004
Three Sisters	1.882	1.802	1.355	1.622	1.882	38	47	21	106	20	24	12	56	76.110	22.980	0.350	0.110	-56.695	-505.881	8/8/2003
Total	**21.213**	**25.313**	**19.861**	**22.707**	**25.653**	**600**	**670**	**564**	**1,834**	**261**	**343**	**234**	**838**							
Maximum	**3.021**	**3.850**	**3.537**	**3.537**	**3.850**	**81**	**86**	**77**	**239**	**56**	**57**	**51**	**164**							
Minimum	**0.617**	**0.846**	**0.423**	**0.747**	**0.846**	**11**	**19**	**6**	**40**	**1**	**7**	**0**	**13**							
Average	**1.515**	**1.808**	**1.419**	**1.622**	**1.832**	**43**	**48**	**40**	**131**	**19**	**25**	**17**	**60**							
Class II Areas*																				
Columbia River Gorge	2.051	2.451	3.232	2.787	3.232	76	78	70	224	46	42	47	135	53.120	46.040	0.320	0.100	-50.325	-357.404	2/26/2005

* Class II area modeled for informational purposes.
LNB = Low NOX Burner, OFA = Overfire Air

Table E-6. Visibility Analysis Results - Wet FGD and PJFF
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

	Delta Deciview													% of Modeled Extinction by Species				Location of Maximum (km)		
	8th High by Year			22nd High	Maximum	Number of Days >0.5				Number of Days >1.0										Date of
Modeled Area	**2003**	**2004**	**2005**	**2003-2005**	**Impact**	**2003**	**2004**	**2005**	**Total**	**2003**	**2004**	**2005**	**Total**	**SO_4**	**NO_3**	**OC**	**EC**	**X**	**Y**	**Maximum**
Class I Areas																				
Alpine Lakes	1.048	1.415	1.430	1.382	1.430	19	38	39	96	9	15	21	45	7.560	91.930	0.200	0.060	22.696	-166.085	10/6/2005
Diamond Peak	0.697	0.599	0.375	0.522	0.697	10	14	2	26	3	2	0	5	10.990	88.410	0.240	0.080	-82.026	-580.788	10/3/2003
Eagle Cap	1.548	1.516	1.139	1.459	1.548	63	53	50	166	21	17	9	47	8.610	90.630	0.280	0.090	246.886	-375.820	2/5/2003
Glacier Peak	0.594	1.027	0.983	0.873	1.027	11	22	25	58	2	8	7	17	13.090	86.170	0.300	0.090	32.559	-90.833	9/25/2004
Goat Rocks	1.086	1.605	1.679	1.533	1.679	28	39	36	103	11	21	20	52	7.420	91.900	0.270	0.090	-29.923	-278.808	3/11/2005
Hells Canyon	1.164	1.185	1.074	1.170	1.185	60	64	50	174	12	13	9	34	8.630	90.330	0.420	0.130	322.494	-379.413	5/4/2004
Mt. Adams	1.300	2.004	1.991	1.923	2.004	31	52	38	121	13	27	21	61	9.830	89.300	0.350	0.110	-43.719	-309.142	9/25/2004
Mt. Hood	3.222	3.525	3.910	3.792	3.910	79	82	72	233	52	59	54	165	8.180	91.170	0.260	0.080	-50.928	-380.287	2/8/2005
Mt. Jefferson	2.524	2.374	1.548	2.162	2.524	48	57	42	147	22	28	14	64	12.970	86.400	0.250	0.080	-51.299	-473.712	1/8/2003
Mt. Rainier	0.999	1.270	1.468	1.297	1.468	24	34	33	91	7	14	18	39	7.090	92.520	0.170	0.050	-66.233	-215.874	1/10/2005
Mt. Washington	1.723	1.438	0.976	1.421	1.723	32	42	23	97	14	15	7	36	9.560	89.680	0.310	0.100	-70.880	-513.788	9/30/2003
North Cascades	0.454	0.651	0.664	0.633	0.664	7	13	12	32	2	3	2	7	8.070	91.460	0.200	0.060	-2.674	-60.475	10/14/2005
Strawberry Mountain	0.874	1.137	0.810	1.001	1.137	25	36	17	78	3	14	5	22	12.370	87.110	0.210	0.060	173.703	-496.528	4/5/2004
Three Sisters	1.452	1.344	1.027	1.311	1.452	34	42	23	99	15	18	9	42	12.430	87.000	0.230	0.070	-57.975	-505.869	1/8/2003
Total	**18.685**	**21.090**	**19.074**	**20.479**	**22.448**	**471**	**588**	**462**	**1,521**	**186**	**254**	**196**	**636**							
Maximum	**3.222**	**3.525**	**3.910**	**3.792**	**3.910**	**79**	**82**	**72**	**233**	**52**	**59**	**54**	**165**							
Minimum	**0.454**	**0.599**	**0.375**	**0.522**	**0.664**	**7**	**13**	**2**	**26**	**2**	**2**	**0**	**5**							
Average	**1.335**	**1.506**	**1.362**	**1.463**	**1.603**	**34**	**42**	**33**	**109**	**13**	**18**	**14**	**45**							
Class II Areas*																				
Columbia River Gorge	2.424	2.749	4.045	3.248	4.045	70	76	76	222	45	48	53	146	7.760	91.610	0.230	0.070	-12.812	-355.812	2/8/2005

* Class II area modeled for informational purposes.
FGD = Flue Gas Desulfurization, PJFF = Pulse Jet Fabric Filter

Table E-7. Visibility Analysis Results - Semi-Dry FGD and PJFF
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

	Delta Deciview													% of Modeled Extinction by Species				Location of Maximum (km)		
	8th High by Year			22nd High	Maximum	Number of Days >0.5				Number of Days >1.0										Date of
Modeled Area	2003	2004	2005	2003-2005	Impact	2003	2004	2005	Total	2003	2004	2005	Total	SO_4	NO_3	OC	EC	X	Y	Maximum
Class I Areas																				
Alpine Lakes	1.114	1.359	1.524	1.422	1.524	21	40	42	103	9	16	23	48	12.160	87.420	0.180	0.060	-23.330	-173.242	3/1/2005
Diamond Peak	0.699	0.631	0.394	0.572	0.699	9	16	3	28	3	2	0	5	15.680	83.740	0.240	0.070	-82.026	-580.788	10/3/2003
Eagle Cap	1.486	1.447	1.081	1.399	1.486	69	50	47	166	20	19	8	47	15.490	82.980	0.610	0.190	246.886	-375.820	8/22/2003
Glacier Peak	0.701	0.833	0.964	0.833	0.964	12	24	29	65	2	7	7	16	12.010	87.650	0.140	0.040	12.905	-117.773	12/30/2005
Goat Rocks	1.101	1.668	1.772	1.582	1.772	32	43	38	113	12	23	20	55	9.040	90.530	0.180	0.050	-22.479	-268.104	2/24/2005
Hells Canyon	1.245	1.246	1.265	1.265	1.265	66	71	58	195	13	14	13	40	7.670	91.440	0.350	0.110	321.350	-334.678	10/29/2005
Mt. Adams	1.456	2.195	1.866	1.981	2.195	35	47	41	123	17	27	21	65	11.100	88.350	0.210	0.070	-43.719	-309.142	2/20/2004
Mt. Hood	3.205	3.736	3.760	3.736	3.760	79	83	73	235	54	59	55	168	13.600	85.420	0.390	0.120	-65.764	-395.065	9/6/2005
Mt. Jefferson	2.512	2.391	1.434	2.139	2.512	50	58	44	152	25	31	12	68	14.530	84.760	0.270	0.090	-65.071	-450.315	1/9/2003
Mt. Rainier	0.990	1.335	1.524	1.335	1.524	24	33	36	93	7	13	18	38	10.360	89.270	0.160	0.050	-66.233	-215.874	1/10/2005
Mt. Washington	1.671	1.555	1.093	1.502	1.671	31	41	21	93	17	15	8	40	13.170	86.150	0.280	0.090	-60.467	-498.685	9/21/2003
North Cascades	0.433	0.732	0.729	0.690	0.732	7	13	15	35	1	4	3	8	18.770	80.850	0.160	0.050	10.409	-65.840	1/9/2004
Strawberry Mountain	0.860	1.202	0.798	1.012	1.202	29	39	17	85	4	14	4	22	13.010	86.380	0.250	0.080	159.632	-496.910	12/20/2004
Three Sisters	1.438	1.374	1.194	1.370	1.438	32	41	21	94	19	18	10	47	15.340	84.220	0.170	0.050	-56.695	-505.881	11/2/2003
Total	**18.911**	**21.704**	**19.398**	**20.838**	**22.744**	**496**	**599**	**485**	**1,580**	**203**	**262**	**202**	**667**							
Maximum	**3.205**	**3.736**	**3.760**	**3.736**	**3.760**	**79**	**83**	**73**	**235**	**54**	**59**	**55**	**168**							
Minimum	**0.433**	**0.631**	**0.394**	**0.572**	**0.699**	**7**	**13**	**3**	**28**	**1**	**2**	**0**	**5**							
Average	**1.351**	**1.550**	**1.386**	**1.488**	**1.625**	**35**	**43**	**35**	**113**	**15**	**19**	**14**	**48**							
Class II Areas*																				
Columbia River Gorge	2.341	2.561	4.008	3.115	4.008	75	77	76	228	47	47	51	145	10.450	88.630	0.340	0.100	8.437	-355.819	2/24/2005

* Class II area modeled for informational purposes.
FGD = Flue Gas Desulfurization, PJFF = Pulse Jet Fabric Filter

Table E-8. Visibility Analysis Results - Reduced Sulfur Coal Restriction (3475.8 lb/hr)
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

Modeled Area	Delta Deciview: 8th High by Year 2003	2004	2005	22nd High 2003-2005	Maximum Impact	Number of Days >0.5: 2003	2004	2005	Total	Number of Days >1.0: 2003	2004	2005	Total	% of Modeled Extinction by Species: SO_4	NO_3	OC	EC	Location of Maximum (km): X	Y	Date of Maximum
Class I Areas																				
Alpine Lakes	1.529	1.906	2.153	1.938	2.153	35	48	54	137	17	27	36	80	29.880	69.660	0.190	0.060	9.387	-169.701	10/27/2005
Diamond Peak	0.927	1.113	0.530	0.901	1.113	14	24	8	46	6	10	0	16	61.100	38.300	0.250	0.080	-88.497	-579.804	8/14/2004
Eagle Cap	2.045	2.223	1.614	2.027	2.223	87	73	72	232	43	37	25	105	39.760	59.700	0.220	0.070	251.678	-370.249	2/29/2004
Glacier Peak	0.937	1.329	1.467	1.237	1.467	22	32	44	98	6	12	19	37	25.880	73.530	0.230	0.070	23.631	-98.936	4/5/2005
Goat Rocks	1.613	2.265	2.157	2.125	2.265	46	51	51	148	21	29	33	83	32.710	66.780	0.200	0.060	-20.003	-264.534	12/16/2004
Hells Canyon	1.704	1.711	1.585	1.711	1.711	101	90	87	278	38	43	26	107	34.270	65.240	0.210	0.060	316.365	-406.615	3/31/2004
Mt. Adams	1.638	2.479	2.697	2.412	2.697	56	57	55	168	21	33	28	82	23.740	75.660	0.240	0.070	-43.719	-309.142	12/12/2005
Mt. Hood	3.741	4.595	4.638	4.550	4.638	84	93	84	261	64	66	61	191	29.920	69.240	0.330	0.100	-47.154	-405.628	3/10/2005
Mt. Jefferson	2.789	2.955	1.722	2.789	2.955	56	68	53	177	35	44	26	105	41.410	57.920	0.280	0.090	-60.045	-455.736	10/2/2004
Mt. Rainier	1.540	1.730	1.882	1.840	1.882	37	47	43	127	15	25	22	62	27.630	71.900	0.210	0.060	-33.402	-239.419	2/24/2005
Mt. Washington	2.122	2.107	1.408	2.004	2.122	38	57	26	121	26	27	13	66	44.150	54.440	0.540	0.170	-59.214	-501.382	7/10/2003
North Cascades	0.719	0.941	1.015	0.904	1.015	16	24	34	74	2	7	8	17	37.000	62.460	0.220	0.070	-13.354	-53.294	10/5/2005
Strawberry Mountain	1.329	1.930	1.078	1.393	1.930	44	61	38	143	20	23	10	53	63.630	35.570	0.330	0.100	159.632	-496.910	6/24/2004
Three Sisters	2.080	2.103	1.429	2.047	2.103	44	60	27	131	25	28	18	71	44.860	54.280	0.360	0.110	-58.093	-518.397	7/22/2004
Total	**24.713**	**29.387**	**25.375**	**27.878**	**30.274**	**680**	**785**	**676**	**2,141**	**339**	**411**	**325**	**1,075**							
Maximum	**3.741**	**4.595**	**4.638**	**4.550**	**4.638**	**101**	**93**	**87**	**278**	**64**	**66**	**61**	**191**							
Minimum	**0.719**	**0.941**	**0.530**	**0.901**	**1.015**	**14**	**24**	**8**	**46**	**2**	**7**	**0**	**16**							
Average	**1.765**	**2.099**	**1.813**	**1.991**	**2.162**	**49**	**56**	**48**	**153**	**24**	**29**	**23**	**77**							
Class II Areas*																				
Columbia River Gorge	2.784	2.874	4.452	3.426	4.452	89	87	78	254	58	53	55	166	26.580	72.630	0.290	0.090	-12.812	-355.812	2/8/2005

* Class II area modeled for informational purposes.
LNB = Low NOX Burner, OFA = Overfire Air

Table E-9. Visibility Analysis Results - New LNB with Modified OFA and RSCR (3475.8 lb/hr)
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

	Delta Deciview														% of Modeled Extinction by Species				Location of Maximum (km)		
	8th High by Year			22nd High	Maximum	Number of Days >0.5				Number of Days >1.0											Date of
Modeled Area	2003	2004	2005	2003-2005	Impact	2003	2004	2005	Total	2003	2004	2005	Total	SO_4	NO_3	OC	EC	X	Y	Maximum
Class I Areas																				
Alpine Lakes	1.065	1.374	1.420	1.317	1.420	22	37	43	102	9	17	18	44	65.580	33.960	0.180	0.050	22.696	-166.085	1/25/2005
Diamond Peak	0.620	0.868	0.324	0.591	0.868	11	15	4	30	4	4	0	8	79.350	19.850	0.320	0.100	-88.497	-579.804	8/14/2004
Eagle Cap	1.337	1.490	1.031	1.330	1.490	60	46	39	145	21	22	9	52	61.870	37.300	0.340	0.100	251.678	-370.249	2/29/2004
Glacier Peak	0.633	0.930	0.933	0.832	0.933	13	24	30	67	1	6	7	14	60.120	39.410	0.200	0.060	12.905	-117.773	1/10/2005
Goat Rocks	1.199	1.547	1.392	1.421	1.547	32	39	37	108	11	21	15	47	72.820	26.390	0.290	0.090	-23.653	-253.783	12/28/2004
Hells Canyon	1.214	1.139	1.028	1.154	1.214	66	57	52	175	15	14	9	38	81.010	17.260	0.720	0.220	321.350	-334.678	7/16/2003
Mt. Adams	1.022	1.768	1.667	1.595	1.768	37	43	38	118	9	24	16	49	74.940	24.640	0.160	0.050	-43.719	-309.142	1/20/2004
Mt. Hood	2.409	3.257	3.068	3.050	3.257	72	79	72	223	51	48	44	143	58.280	40.820	0.340	0.110	-49.716	-407.458	11/10/2004
Mt. Jefferson	1.959	2.037	1.103	1.901	2.037	49	53	36	138	24	27	11	62	63.100	35.870	0.430	0.130	-60.045	-455.736	10/2/2004
Mt. Rainier	1.073	1.207	1.191	1.191	1.207	23	31	30	84	8	15	15	38	69.000	30.590	0.170	0.050	-42.020	-244.733	12/18/2004
Mt. Washington	1.525	1.457	0.951	1.387	1.525	31	40	20	91	16	16	7	39	70.800	28.090	0.430	0.130	-60.467	-498.685	8/8/2003
North Cascades	0.487	0.647	0.671	0.607	0.671	6	11	15	32	1	5	2	8	76.350	23.330	0.130	0.040	-33.458	-40.670	1/28/2005
Strawberry Mountain	0.942	1.339	0.669	1.037	1.339	32	38	18	88	7	12	4	23	63.600	35.230	0.460	0.140	159.632	-496.910	3/2/2004
Three Sisters	1.517	1.462	1.132	1.334	1.517	32	40	21	93	15	17	8	40	64.630	33.310	0.790	0.240	-56.695	-505.881	7/10/2003
Total	**17.002**	**20.522**	**16.580**	**18.747**	**20.793**	**486**	**553**	**455**	**1,494**	**192**	**248**	**165**	**605**							
Maximum	**2.409**	**3.257**	**3.068**	**3.050**	**3.257**	**72**	**79**	**72**	**223**	**51**	**48**	**44**	**143**							
Minimum	**0.487**	**0.647**	**0.324**	**0.591**	**0.671**	**6**	**11**	**4**	**30**	**1**	**4**	**0**	**8**							
Average	**1.214**	**1.466**	**1.184**	**1.339**	**1.485**	**35**	**40**	**33**	**107**	**14**	**18**	**12**	**43**							
Class II Areas*																				
Columbia River Gorge	1.812	1.989	2.826	2.342	2.826	69	67	63	199	35	34	43	112	45.650	52.980	0.500	0.160	-12.812	-355.812	2/8/2005

* Class II area modeled for informational purposes.
LNB = Low NOX Burner, OFA = Overfire Air

Table E-10. Summary of Visibility Analysis Results and Comparison of Change in Visibility (Δdv)
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

	Existing Controls	NO_X Control Alternatives									SO_2 Control Alternatives									Combined NO_X and SO_2		
	Baseline	NLNB/MOFA/SCR			NLNB/MOFA/SNCR			NLNB/MOFA			Wet FGD/PJFF			Semi-Dry FGD/PJFF			RSCR			NLNB/MOFA/RSCR		
	98th %tile	98th %tile	Improvement		98th %tile	Improvement		98th %tile	Improvement		98th %tile	Improvement		98th %tile	Improvement		98th %tile	Improvement		98th %tile	Improvement	
Modeled Area	(Δdv)	(Δdv)	(dv)	(%)	(Δdv)	(dv)	(%)	(Δdv)	(dv)	(%)	(Δdv)	(dv)	(%)	(Δdv)	(dv)	(%)	(Δdv)	(dv)	(%)	(Δdv)	(dv)	(%)
Class I Areas																						
Alpine Lakes	2.370	1.428	0.942	39.7	1.686	0.684	28.9	1.763	0.607	25.6	1.430	0.940	39.7	1.524	0.846	35.7	2.153	0.217	9.2	1.420	0.950	40.1
Diamond Peak	1.368	0.931	0.437	31.9	1.070	0.298	21.8	1.114	0.254	18.6	0.697	0.671	49.0	0.699	0.669	48.9	1.113	0.255	18.6	0.868	0.500	36.5
Eagle Cap	2.537	1.471	1.066	42.0	1.724	0.813	32.0	1.815	0.722	28.5	1.548	0.989	39.0	1.486	1.051	41.4	2.223	0.314	12.4	1.490	1.047	41.3
Glacier Peak	1.621	1.081	0.540	33.3	1.081	0.540	33.3	1.141	0.480	29.6	1.027	0.594	36.6	0.964	0.657	40.5	1.467	0.154	9.5	0.933	0.688	42.4
Goat Rocks	2.533	1.749	0.784	31.0	1.883	0.650	25.7	1.946	0.587	23.2	1.679	0.854	33.7	1.772	0.761	30.0	2.265	0.268	10.6	1.547	0.986	38.9
Hells Canyon	1.978	1.242	0.736	37.2	1.379	0.599	30.3	1.486	0.492	24.9	1.185	0.793	40.1	1.265	0.713	36.0	1.711	0.267	13.5	1.214	0.764	38.6
Mt. Adams	2.888	1.851	1.037	35.9	2.181	0.707	24.5	2.249	0.639	22.1	2.004	0.884	30.6	2.195	0.693	24.0	2.697	0.191	6.6	1.768	1.120	38.8
Mt. Hood	5.136	3.248	1.888	36.8	3.657	1.479	28.8	3.850	1.286	25.0	3.910	1.226	23.9	3.760	1.376	26.8	4.638	0.498	9.7	3.257	1.879	36.6
Mt. Jefferson	3.349	2.271	1.078	32.2	2.392	0.957	28.6	2.493	0.856	25.6	2.524	0.825	24.6	2.512	0.837	25.0	2.955	0.394	11.8	2.037	1.312	39.2
Mt. Rainier	2.095	1.476	0.619	29.5	1.458	0.637	30.4	1.518	0.577	27.5	1.468	0.627	29.9	1.524	0.571	27.3	1.882	0.213	10.2	1.207	0.888	42.4
Mt. Washington	2.437	1.613	0.824	33.8	1.824	0.613	25.2	1.906	0.531	21.8	1.723	0.714	29.3	1.671	0.766	31.4	2.122	0.315	12.9	1.525	0.912	37.4
North Cascades	1.151	0.690	0.461	40.1	0.833	0.318	27.6	0.846	0.305	26.5	0.664	0.487	42.3	0.732	0.419	36.4	1.015	0.136	11.8	0.671	0.480	41.7
Strawberry Mountain	2.238	1.291	0.947	42.3	1.566	0.672	30.0	1.644	0.594	26.5	1.137	1.101	49.2	1.202	1.036	46.3	1.930	0.308	13.8	1.339	0.899	40.2
Three Sisters	2.425	1.596	0.829	34.2	1.813	0.612	25.2	1.882	0.543	22.4	1.452	0.973	40.1	1.438	0.987	40.7	2.103	0.322	13.3	1.517	0.908	37.4
Total	**34.126**	**21.938**	**12.188**	**35.7**	**24.547**	**9.579**	**28.1**	**25.653**	**8.473**	**24.8**	**22.448**	**11.678**	**34.2**	**22.744**	**11.382**	**33.4**	**30.274**	**3.852**	**11.3**	**20.793**	**13.333**	**39.1**
Maximum	**5.136**	**3.248**	**1.888**	**42.3**	**3.657**	**1.479**	**33.3**	**3.850**	**1.286**	**29.6**	**3.910**	**1.226**	**49.2**	**3.760**	**1.376**	**48.9**	**4.638**	**0.498**	**18.6**	**3.257**	**1.879**	**42.4**
Minimum	**1.151**	**0.690**	**0.437**	**29.5**	**0.833**	**0.298**	**21.8**	**0.846**	**0.254**	**18.6**	**0.664**	**0.487**	**23.9**	**0.699**	**0.419**	**24.0**	**1.015**	**0.136**	**6.6**	**0.671**	**0.480**	**36.5**
Average	**2.438**	**1.567**	**0.871**	**35.7**	**1.753**	**0.684**	**28.0**	**1.832**	**0.605**	**24.8**	**1.603**	**0.834**	**36.3**	**1.625**	**0.813**	**35.0**	**2.162**	**0.275**	**11.7**	**1.485**	**0.952**	**39.4**
Class II Areas*																						
Columbia River Gorge	4.758	2.504	2.254	47.4	3.003	1.76	36.9	3.232	1.53	32.1	4.045	0.71	15.0	4.008	0.75	15.8	4.452	0.31	6.4	2.826	1.93	40.6

* Class II area modeled for informational purposes.
NLNB = New Low NOX Burner, MOFA = Modified Overfire Air, SCR = Selective Catalytic Reduction, SNCR = Selective Non-Catalytic Reduction, FGD = Flue Gas Desulfurization, PJFF = Pulse Jet Fabric Filter, RSCR = Reduced Sulfur Coal Restriction

Table E-11. Summary of Visibility Analysis Results and Comparison of Total Number of Days Above 0.5 Deciview
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

	Existing Controls	NO_X Control Alternatives									SO_2 Control Alternatives									Combined NO_X and SO_2		
	Baseline	NLNB/MOFA/SCR			NLNB/MOFA/SNCR			NLNB/MOFA			Wet FGD/PJFF			Semi-Dry FGD/PJFF			RSCR			NLNB/MOFA/RSCR		
	Total Days	Total Days	Improvement		Total Days	Improvement		Total Days	Improvement		Total Days	Improvement		Total Days	Improvement		Total Days	Improvement		Total Days	Improvement	
Modeled Area	(days)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)
Class I Areas																						
Alpine Lakes	152	101	51	33.6	117	35	23.0	123	29	19.1	96	56	36.8	103	49	32.2	137	15	9.9	102	50	32.9
Diamond Peak	60	29	31	51.7	37	23	38.3	40	20	33.3	26	34	56.7	28	32	53.3	46	14	23.3	30	30	50.0
Eagle Cap	265	157	108	40.8	182	83	31.3	196	69	26.0	166	99	37.4	166	99	37.4	232	33	12.5	145	120	45.3
Glacier Peak	118	65	53	44.9	80	38	32.2	90	28	23.7	58	60	50.8	65	53	44.9	98	20	16.9	67	51	43.2
Goat Rocks	157	106	51	32.5	127	30	19.1	131	26	16.6	103	54	34.4	113	44	28.0	148	9	5.7	108	49	31.2
Hells Canyon	324	164	160	49.4	213	111	34.3	221	103	31.8	174	150	46.3	195	129	39.8	278	46	14.2	175	149	46.0
Mt. Adams	185	121	64	34.6	138	47	25.4	145	40	21.6	121	64	34.6	123	62	33.5	168	17	9.2	118	67	36.2
Mt. Hood	270	212	58	21.5	234	36	13.3	239	31	11.5	233	37	13.7	235	35	13.0	261	9	3.3	223	47	17.4
Mt. Jefferson	188	139	49	26.1	152	36	19.1	161	27	14.4	147	41	21.8	152	36	19.1	177	11	5.9	138	50	26.6
Mt. Rainier	145	87	58	40.0	101	44	30.3	102	43	29.7	91	54	37.2	93	52	35.9	127	18	12.4	84	61	42.1
Mt. Washington	135	96	39	28.9	105	30	22.2	107	28	20.7	97	38	28.1	93	42	31.1	121	14	10.4	91	44	32.6
North Cascades	83	32	51	61.4	48	35	42.2	54	29	34.9	32	51	61.4	35	48	57.8	74	9	10.8	32	51	61.4
Strawberry Mountain	172	86	86	50.0	111	61	35.5	119	53	30.8	78	94	54.7	85	87	50.6	143	29	16.9	88	84	48.8
Three Sisters	137	94	43	31.4	106	31	22.6	106	31	22.6	99	38	27.7	94	43	31.4	131	6	4.4	93	44	32.1
Total	**2,391**	**1,489**	**902**	**37.7**	**1,751**	**640**	**26.8**	**1,834**	**557**	**23.3**	**1,521**	**870**	**36.4**	**1,580**	**811**	**33.9**	**2,141**	**250**	**10.5**	**1,494**	**897**	**37.5**
Maximum	**324**	**212**	**160**	**61.4**	**234**	**111**	**42.2**	**239**	**103**	**34.9**	**233**	**150**	**61.4**	**235**	**129**	**57.8**	**278**	**46**	**23.3**	**223**	**149**	**61.4**
Minimum	**60**	**29**	**31**	**21.5**	**37**	**23**	**13.3**	**40**	**20**	**11.5**	**26**	**34**	**13.7**	**28**	**32**	**13.0**	**46**	**6**	**3.3**	**30**	**30**	**17.4**
Average	**171**	**106**	**64**	**39.0**	**125**	**46**	**27.8**	**131**	**40**	**24.1**	**109**	**62**	**38.7**	**113**	**58**	**36.3**	**153**	**18**	**11.1**	**107**	**64**	**39.0**
Class II Areas*																						
Columbia River Gorge	267	193	74	27.7	217	50	18.7	224	43	16.1	222	45	16.9	228	39	14.6	254	13	4.9	199	68	25.5

* Class II area modeled for informational purposes.
NLNB = New Low NOX Burner, MOFA = Modified Overfire Air, SCR = Selective Catalytic Reduction, SNCR = Selective Non-Catalytic Reduction, FGD = Flue Gas Desulfurization, PJFF = Pulse Jet Fabric Filter, RSCR = Reduced Sulfur Coal Restriction

Table E-12. Summary of Visibility Analysis Results and Comparison of Total Number of Days Above 1.0 Deciview
BART/Reasonable Progress Analysis Revision 2: Boardman 2020 Alternative
Portland General Electric - Boardman, OR

	Existing Controls	NO_X Control Alternatives									SO_2 Control Alternatives									Combined NO_X and SO_2		
	Baseline	NLNB/MOFA/SCR			NLNB/MOFA/SNCR			NLNB/MOFA			Wet FGD/PJFF			Semi-Dry FGD/PJFF			RSCR			NLNB/MOFA/RSCR		
	Total Days	Total Days	Improvement		Total Days	Improvement		Total Days	Improvement		Total Days	Improvement		Total Days	Improvement		Total Days	Improvement		Total Days	Improvement	
Modeled Area	(days)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)	(days)	(days)	(%)
Class I Areas																						
Alpine Lakes	91	43	48	52.7	58	33	36.3	62	29	31.9	45	46	50.5	48	43	47.3	80	11	12.1	44	47	51.6
Diamond Peak	24	9	15	62.5	13	11	45.8	14	10	41.7	5	19	79.2	5	19	79.2	16	8	33.3	8	16	66.7
Eagle Cap	122	53	69	56.6	74	48	39.3	79	43	35.2	47	75	61.5	47	75	61.5	105	17	13.9	52	70	57.4
Glacier Peak	46	17	29	63.0	19	27	58.7	22	24	52.2	17	29	63.0	16	30	65.2	37	9	19.6	14	32	69.6
Goat Rocks	92	48	44	47.8	58	34	37.0	62	30	32.6	52	40	43.5	55	37	40.2	83	9	9.8	47	45	48.9
Hells Canyon	136	38	98	72.1	61	75	55.1	67	69	50.7	34	102	75.0	40	96	70.6	107	29	21.3	38	98	72.1
Mt. Adams	101	48	53	52.5	63	38	37.6	68	33	32.7	61	40	39.6	65	36	35.6	82	19	18.8	49	52	51.5
Mt. Hood	206	141	65	31.6	158	48	23.3	164	42	20.4	165	41	19.9	168	38	18.4	191	15	7.3	143	63	30.6
Mt. Jefferson	124	68	56	45.2	85	39	31.5	90	34	27.4	64	60	48.4	68	56	45.2	105	19	15.3	62	62	50.0
Mt. Rainier	69	36	33	47.8	46	23	33.3	50	19	27.5	39	30	43.5	38	31	44.9	62	7	10.1	38	31	44.9
Mt. Washington	76	44	32	42.1	54	22	28.9	56	20	26.3	36	40	52.6	40	36	47.4	66	10	13.2	39	37	48.7
North Cascades	24	10	14	58.3	12	12	50.0	13	11	45.8	7	17	70.8	8	16	66.7	17	7	29.2	8	16	66.7
Strawberry Mountain	77	21	56	72.7	31	46	59.7	35	42	54.5	22	55	71.4	22	55	71.4	53	24	31.2	23	54	70.1
Three Sisters	77	41	36	46.8	54	23	29.9	56	21	27.3	42	35	45.5	47	30	39.0	71	6	7.8	40	37	48.1
Total	**1,265**	**617**	**648**	**51.2**	**786**	**479**	**37.9**	**838**	**427**	**33.8**	**636**	**629**	**49.7**	**667**	**598**	**47.3**	**1,075**	**190**	**15.0**	**605**	**660**	**52.2**
Maximum	**206**	**141**	**98**	**72.7**	**158**	**75**	**59.7**	**164**	**69**	**54.5**	**165**	**102**	**79.2**	**168**	**96**	**79.2**	**191**	**29**	**33.3**	**143**	**98**	**72.1**
Minimum	**24**	**9**	**14**	**31.6**	**12**	**11**	**23.3**	**13**	**10**	**20.4**	**5**	**17**	**19.9**	**5**	**16**	**18.4**	**16**	**6**	**7.3**	**8**	**16**	**30.6**
Average	**90**	**44**	**46**	**53.7**	**56**	**34**	**40.5**	**60**	**31**	**36.2**	**45**	**45**	**54.6**	**48**	**43**	**52.3**	**77**	**14**	**17.3**	**43**	**47**	**55.5**
Class II Areas*																						
Columbia River Gorge	174	106	68	39.1	126	48	27.6	135	39	22.4	146	28	16.1	145	29	16.7	166	8	4.6	112	62	35.6

* Class II area modeled for informational purposes.
NLNB = New Low NOX Burner, MOFA = Modified Overfire Air, SCR = Selective Catalytic Reduction, SNCR = Selective Non-Catalytic Reduction, FGD = Flue Gas Desulfurization, PJFF = Pulse Jet Fabric Filter, RSCR = Reduced Sulfur Coal Restriction

Appendix F
Visibility Modeling Protocol

Modeling Protocol for
Washington, Oregon, and Idaho:
Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation

1. Introduction and Protocol Objective

1.1 *Background*

Under the Regional Haze Regulations, the U.S. Environmental Protection Agency (EPA) issued the final Guidelines for Best Available Retrofit Technology (BART) Determinations (July 6, 2005) (BART Guideline). According to the Regional Haze Rule, States are required to use these guidelines for establishing BART emission limitations for fossil fuel fired power plants having a capacity in excess of 750 megawatts. The use of these guidelines is optional for states establishing BART emission limitations for other BART-eligible sources. However, according to EPA, the BART Guideline was designed to help states and others do the following: (1) identify those sources that must comply with the BART requirement, and (2) determine the level of control technology that represents BART for each source.

This modeling protocol is a cooperative effort among Idaho Department of Environmental Quality (IDEQ), Oregon Department of Environmental Quality (ODEQ), and Washington Department of Ecology (WDOE) to develop an analysis that will be applied consistently to Idaho, Washington, and Oregon BART-eligible sources. The U.S. Fish and Wildlife Service, National Park Service, U.S. Forest Service, and U.S. EPA Region 10 were consulted during the development of this protocol (EPA 2006a, b, c). This protocol adopts the BART Guideline and addresses both the BART exemption modeling as well as the BART determination modeling. The three agencies are also collaborating on the development of a consistent three-year meteorological data set. Collaboration on the protocol and meteorological data set helps ensure modeling consistency and the sharing of resources and workload.

1.2 *Objectives*

The protocol describes the modeling methodology that will be used for the following purposes:

- **BART Exemption modeling** – Evaluating whether a BART-eligible source is exempt from BART controls because it is not reasonably anticipated to cause or contribute to impairment of visibility in Class I areas
- **BART Determination modeling** – Quantifying the visibility improvements of BART control options

The objectives of this protocol are to provide the following:

- A streamlined and consistent approach in determining which BART-eligible sources are subject to BART
- A clearly delineated modeling methodology
- A common CALMET/CALPUFF/POSTUTIL/CALPOST modeling configuration

2. Modeling Approach

2.1 *Bart-Eligible Source List*

BART-eligible source refers to the entire facility that has BART-eligible emission units.

Oregon, Washington, and Idaho are in the process of finalizing lists of BART-eligible sources. Table 1 presents the BART-eligible lists, as of July 21, 2006. Sources may be added/removed as additional information is reviewed.

Table 1. BART-eligible sources.

Washington	Oregon	Idaho
Intalco Aluminum	Amalgamated Sugar	Amalgamated Sugar – Nampa
Conoco-Phillips	PGE Boardman	Amalgamated Sugar – Paul
Centralia Powerplant (TransAlta)	Boise Cascade	Amalgamated Sugar – Twin Falls
Longview Fibre	Fort James	J.R. Simplot Don Siding Plant
Weyerhaeuser – Longview	Pope & Talbot	Potlatch Pulp and Paper
BP Cherry Point	Weyerhaeuser	Monsanto
Tesoro NW	PGE Beaver	NuWest (Agrium)
Lafarge	Georgia Pacific	
Georgia Pacific (Fort James) Camas	Smurfit	
Port Townsend Paper	Kingsford	
Simpson Tacoma Kraft		
Shell (Puget Sound Refining Co)		
Graymont Western		
Alcoa-Wenatchee		
Columbia		

2.2 *Class I Areas*

The mandatory Class I federal areas in Idaho, Oregon, and Washington, as well as neighboring states that could be impacted by BART-eligible sources, are presented in Appendix A. Figure A-1 graphically presents the BART-eligible source locations with respect to the Class I areas.

All federally mandatory Class I areas within 300 kilometers (km) of a BART-eligible source will be included in the BART exemption modeling analysis. Section 6.1(c) of the Guideline on Air Quality Models states, "It was concluded from these case studies that the CALPUFF dispersion model had performed in a reasonable manner, and had no apparent bias toward over or under prediction, so long as the transport distance was limited to less than 300km" (40 CFR 51, Appendix W). If the 300km extends into a neighboring state, visibility impairment shall also be quantified at those Class I areas. Furthermore, if it lies within the 300km radius, visibility impairment at the Columbia River Gorge Scenic Area will also be quantified for information purposes only.

2.3 *Pollutants to Consider*

The BART Guideline specifies that sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and direct particulate matter (PM) emissions, including both PM_{10} and $PM_{2.5}$ should be included for both the BART exemption and BART determination modeling analyses.

The BART Guideline also discusses the inclusion of volatile organic compound (VOC), ammonia and ammonia compounds as visibility impairing pollutants. These pollutants will be included in the BART analysis if it is determined that they are reasonably anticipated to cause or contribute to visibility impairment. For sources that are selected to evaluate VOC emissions, the first criterion is the emission level. The VOC emissions will be included in the BART exemption analysis if the greater-than-six-carbon VOC gases exceed 250 tons-per-year. If speciation is not known, it will be conservatively assumed that 50% of the gas species within the total VOC emissions from a facility have greater than six carbon atoms. Idaho and Oregon have determined that there are no significant sources of VOC, ammonia, or ammonia compounds which require a full BART exemption analysis.

2.4 *Emissions and Stack Data*

The BART Guideline states, "*the emission estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization.*" These emissions should not generally include start-up, shutdown, or malfunction emissions. The BART Guideline recommends that states use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled. The meteorological period is 2003 – 2005.

Depending on the availability of emissions data, the following emissions information (listed in order of priority) should be used with CALPUFF for BART exemption modeling:

- 24-hour average actual emission rate from the highest emitting day within the modeling period (2003 – 2005) (preferred). Actual emissions may be calculated using emission factors specified in Title V permits or representative stack test; or
- Allowable emissions (maximum 24-hour allowable).

States will work with the BART-eligible sources to develop an appropriate emission inventory.

If plant-wide emissions from all BART eligible units for SO_2, NO_x, and PM_{10} are less than the significant emission rate (SER) used for Prevention of Significant Deterioration, emissions of that pollutant will not be included in the BART exemption modeling. However, if plant-wide emissions from all BART eligible units exceed the SERs for these pollutants, then all emissions of that pollutant from individual emission units will be evaluated even if emissions are below the SER for an individual emission unit.

The states have the option of determining how to include small emission units in the BART exemption analysis. Fugitive dust sources at a distance greater than 10km from any Class I area are exempt from the analysis. Emission units with emissions less than the SER will be quantified, if possible, and added to the stack emissions from an emission unit that is already being evaluated. Thus, the emissions from these small units will be included in the total from the plant, but will not have to be modeled separately.

2.5 *Natural Background*

The natural visibility background is defined as the 20% best days. This definition of natural background is consistent with the intent of the BART Guideline (Federal Register Vol. 70, No. 128, pf 39125). The natural background values for Class I areas used in this protocol are based on EPA's "Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule" (EPA 2003). The natural background for the Columbia River Gorge Scenic Area is based on IMPROVE monitoring data, and was supplied by Scott Copeland of CIRA (Cooperative Institute for Research in the Atmosphere). These background data for Class I areas and the Columbia River Gorge are presented in Appendix B. The option presented in EPA's guidance for refining the default visibility background is not to be used in this protocol.

2.6 *Visibility Calculation*

The CALPUFF modeling techniques presented in this protocol will provide ground level concentrations of visibility impairing pollutants. The concentration estimates from CALPUFF are used with the current FLAG equation to calculate the extinction coefficient, as shown below.

$b_{ext} = 3\ f(RH)\ [(NH_4)_2SO_4] + 3\ f(RH)\ [NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray}$

As described in the IWAQM Phase 2 Report, the change in visibility for the BART exemption analysis is compared against background conditions. The delta-deciview, Δdv, value is calculated from the source's contribution to extinction, $b_{ext\ (source)}$, and background extinction, $b_{ext(bkg)}$, as follows:

$$\Delta dv = 10\ ln\ [\ (\ b_{ext(bkg)} + b_{ext\ (source)}\ ) / (\ b_{ext(bkg)}\ )\ ]$$

2.7 *Model Execution*

2.7.1 BART Exemption Analysis

The BART exemption modeling determines which BART-eligible sources are reasonably anticipated to cause or contribute to visibility impairment at any Class I area. This protocol adopts Option 1 in Section III of the BART Guideline. This option is the Individual Source Attribution Approach. With this approach, each BART-eligible source is modeled separately and the impact on visibility impairment in any Class I area is determined. However, this protocol also allows the state or other authority to include all BART-eligible sources in a single analysis and determine whether or not all sources together are exempt from BART if the total impact on visibility impairment at any Class I area is below the "contribute" threshold.

Sources, or in some cases groups of sources, that exceed the threshold will be considered subject to BART. Sources or groups of sources with modeled impairment below the threshold will be exempt and excused from further analyses.

For determining the visibility threshold, the recommendations in the BART Guideline are followed to assess whether a BART-eligible source is reasonably anticipated to cause or contribute to any visibility impairment in a Class I area. According to the BART Guideline:

"A single source that is responsible for a 1.0 deciview change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 deciview change may still contribute to visibility impairment and thus be subject to BART… As a general matter, any threshold that you used for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 deciviews.

In setting a threshold for "contribution," you should consider the number of emissions sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts. In general, a larger number of sources causing impacts in a Class I area may warrant a lower contribution threshold. States remain free to use a threshold lower than 0.5 deciviews if they conclude that the location of a large number of BART-eligible sources within the State and in proximity to a Class I area justify this approach."

As a result, this protocol has determined that if a single source causes a 0.5 deciview or greater change from natural background, then that source is determined to be reasonably anticipated to contribute to any visibility impairment in a Class I area and will be subject to BART. For this single source analysis, the BART exemption modeling will not consider the frequency, magnitude, and duration of impairment.

In addition, as suggested by the BART Guideline, if multiple BART-eligible sources impact a given Class I area on the same day, then a lower, individual, contribution threshold may be considered. For BART-eligible sources in Oregon and Washington, the following steps will be used to address this condition: 1) after all BART-eligible sources have completed their individual BART exemption modeling, the modeled visibility impairment from all sources will be aggregated for each Class I area receptor for each day; 2) if the total for any receptor exceeds 0.5 deciview, all sources responsible for visibility impairment at that receptor for that day will be considered for further evaluation. This evaluation will include an assessment of the magnitude, frequency, duration of impairment, and other factors that affect visibility for each of the sources in the multi-source group. The inclusion of these qualifying factors in the multi-source analysis follows the direction given in the BART Guideline for interpreting the refined modeling results in the determination phase of the BART process and recommendations for sources subject to PSD analyses given in the FLAG Phase I Final Report (FLAG 2000). There is no set individual source visibility threshold for these multi-source assessments. After the multi-source evaluation, a determination will be made as to which sources, if any, from a multi-source group will be considered to have contributed to visibility impairment and be subject to BART.

2.7.2 BART Determination Analysis

The BART Determination analysis determines the degree of visibility improvement for each control option. The BART Guideline states:

"Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have the flexibility to assess visibility improvement due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment."

In order to quantify the degree of visibility improvement due to BART controls, the modeling system is executed in a similar manner as for the BART exemption analysis. Model execution and results are needed for both pre-BART control and post-BART control scenarios to allow for comparison of CALPOST delta-deciview predictions for both scenarios. The only difference between the modeling runs will be modifications to the CALPUFF inputs associated with control devices (emissions, stack parameters). In contrast to the BART exemption analysis that predicts pre-control impacts from all BART-eligible units at a source together, BART determination analyses evaluates each emission unit independently of each other after control options are in place. As explained in the BART Guideline, the states may consider the frequency, magnitude, and duration of impairment for the determination analysis.

2.7.3 Implementing BART Modeling Analysis

Each state will implement the BART analysis separately, as follows:

- Idaho – DEQ will perform both the BART exemption and BART determination modeling, working closely with the facilities and providing the facilities with the modeling analysis if they too want to perform the analysis.

- Oregon – DEQ will perform the BART exemption analysis and the individual BART-subject facilities will perform the BART determination analysis. Oregon DEQ will perform any cumulative analysis required.

- Washington – The Washington BART-eligible sources will conduct the BART exemption modeling and the BART determination analysis. Ecology and EPA will conduct any cumulative analysis required.

3. Visibility Modeling System

In general, the BART exemption modeling using the CALPUFF suite of programs will follow the procedures and recommendations outlined in two documents: the IWAQM (Interagency Workgroup on Air Quality Models) and the FLAG (Federal Land Managers Air Quality Related Values Workgroup) reports (EPA 1998, FLAG 2000). Exceptions to these procedures are explicitly described in the appropriate sections below. Tables listing the modeling parameters for each CALPUFF module are located in the Appendices.

The specific CALPUFF programs and their version numbers that will be used in both the exemption modeling and determination modeling (control evaluation) are presented in Table 2.

The CALMET meteorological domain, as described below, covers the full three-state area. The computational domains, which will be unique for each source or group of sources undergoing modeling, will be a subset of the meteorological domain. As a result, a consistent meteorological data set will be used in all analyses, but the computational domains will be tailored to suit the modeling requirements for each individual source and the Class I areas within a radius of 300km.

Table 2. CALPUFF Modeling System

Program	Version	Level
CALMET	6.211	060414
CALPUFF	6.112	060412
CALPOST	6.131	060410
POSTUTIL	1.52	060412

3.1 CALMET

The dispersion modeling will use CALMET windfields for the three-year period 2003-2005. These windfields cover the three-state area of Washington, Oregon, and Idaho, and also extend into adjacent states sufficiently to encompass all Class I areas within 300km of any BART-eligible facility included in this analysis (Figure 1). As part of the three-state collaboration on a BART protocol, it was decided to support the development of a consistent meteorological data set for use in both the BART exemption and determination analyses. Therefore, the states contracted with a consulting firm, Geomatrix, to provide this set of meteorological data for use in CALPUFF for determining whether a BART-eligible source is reasonably anticipated to cause or contribute to haze in a Federal Class I area.

One of the deliverables of that contract is a final CALMET modeling protocol that provides details on the methodology used to develop the data sets. Therefore, this BART modeling protocol only summarizes the development of the CALMET data set. For additional detail, the reader is referred to the "*Modeling Protocol for BART CALMET Datasets*" in Attachment 1.

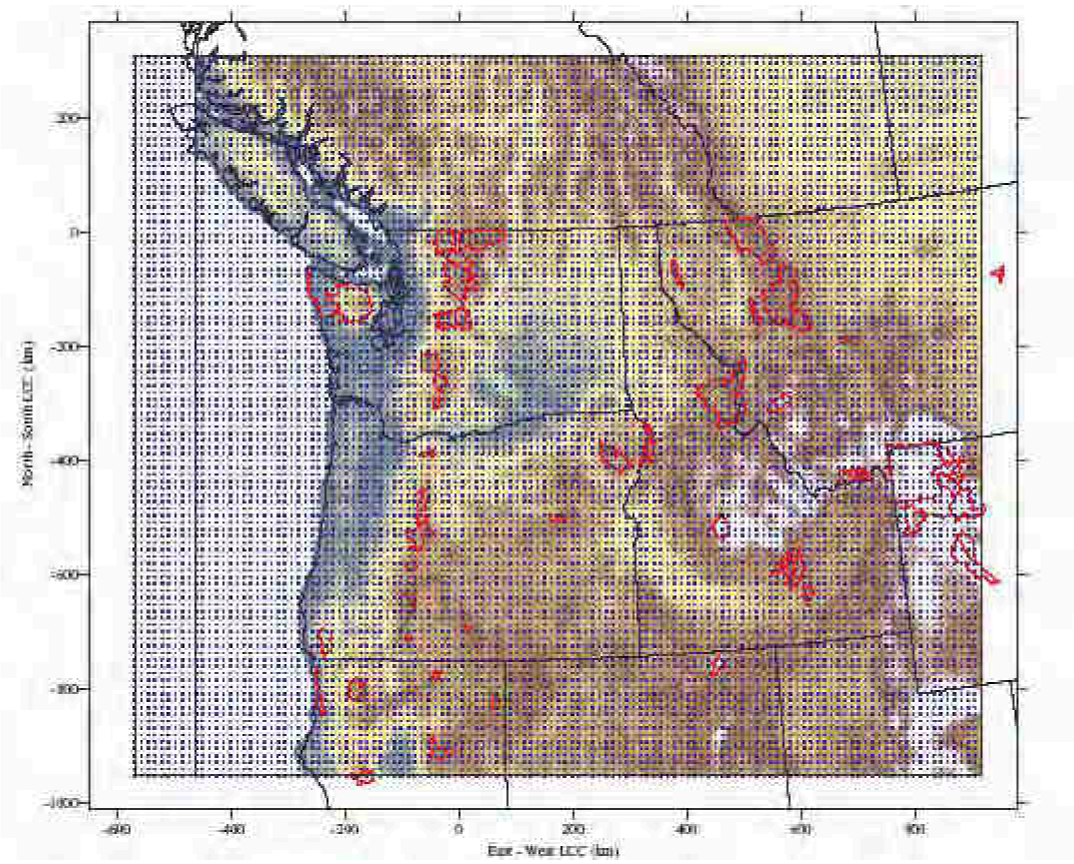

Figure 1. CALMET Meteorological Domain.

3.2 *Meteorological Data*

3.2.1 Mesoscale Model Data

It was the judgment of Idaho, Oregon, Washington, and EPA Region 10 that the use of three years of MM5 data developed by Western Regional Air Partnership (WRAP) would not adequately capture the meteorology in the Pacific Northwest. WRAP had run MM5 using 36-km and 12-km grids. The states and EPA Region 10 preferred a 4-km grid as it would more adequately capture the meteorology and the influences of complex terrain that characterizes the Region 10 area. Furthermore, WRAP had selected some physics options that are more appropriate for the dry southwest and not the wet northwest.

As a result, the three states contracted a consulting firm (Geomatrix) to process calendar year 2003 to 2005 forecast 12-km MM5 output files archived at the University of Washington (UW). The 12-km MM5 domain includes all of Idaho, Oregon and Washington. Portions of Montana, Wyoming, Utah, Nevada and California are also included in the domain so that BART-eligible sources near these state borders that could impact Class I areas outside of Region 10 are considered in the analysis.

The MM5 data was evaluated for model performance using the statistical evaluation tool

METSTAT. CALMET Version 6.211, including a new over-water algorithm, was used to interpolate the 12-km data down to 4-km for the entire domain. The CALMET outputs were also evaluated to determine the model performance of the CALMET wind fields. At this time, METSTAT is unable to evaluate CALMET files. The statistical benchmarks listed in the WRAP Draft Final Report Annual 2002 MM5 Meteorological Modeling to Support Regional Haze Modeling of the Western United States (ENVIRON and UCR, 2005) served as a guide for the acceptability of the MM5 data and CALMET output.

CALMET allows the user to adjust the MM5 wind fields in varying degree by the introduction of observational data, including surface, over-water, and upper air data (using the so-called NOOBS parameter). Idaho, Oregon, and Washington have determined that the observed cloud cover should be used, but that observed surface and upper air winds should not be included in CALMET as they locally distort the MM5 wind fields and have no significant effect on long range transport. As a result, the three states have judged that the MM5 simulations more than adequately characterize the regional wind patterns. It should also be noted that CALMET uses the finer scale land use and digital elevation model (DEM) data to interpolate the MM5 winds down to 4km, which improve the wind flow patterns in complex terrain within the modeling domain.

3.2.2 CALMET Control File Settings

These CALMET wind fields will be used by all BART-eligible sources within the three states for both BART exemption and BART determination modeling. The wind fields have been computed by Geomatrix using CALMET Version 6.211. Details of the parameter settings in CALMET are provided in Appendix C; however, the major assumptions are summarized below.

1) The initial-guess fields used the 12-km MM5 outputs, forecast hours 13 – 24 from every 00Z and 12Z initialization, taken from UW archives, for the three years, January 2003 – December, 2005.

2) Both the BART exemption and determination modeling will utilize the wind fields at 4km resolution.

3) The meteorological data was evaluated in two stages using the extensive database of surface observations maintained by UW. First, the MM5 12-km data was evaluated prior to running CALMM5 using the METSTAT software program and secondly, the wind fields generated by CALMET was evaluated using standard statistical evaluation techniques.

4) There are 10 vertical layers with face heights of 0, 20, 40, 65, 120, 200, 400, 700, 1200, 2200, and 4000 meters.

5) CALMET was run using NOOBS = 1. Upper air, precipitation, and relative humidity data were taken from MM5.

6) The surface wind observations were ignored by setting the relative weight of surface winds to essentially zero (R1 = 1.0E-06). The only surface observation data that was effectively used in CALMET is cloud cover. This is essentially a no-observation approach. This method is specified in this protocol because previous modeling in the Pacific Northwest shows that the radius of influence of a typical surface wind observation must be set at a small number because of the presence of local topographic features. As a result, the adjustment to or distortion of wind fields by surface observations is extremely localized, on the order of 10-15km, and has no effect on long range transport to Class I areas.

7) Precipitation data was obtained from MM5, so MM5NPSTA = -1

8) No weighting of surface and upper air observations, and BIAS = 0, and ICALM = 0

9) The terrain scale factor TERRAD = 12

10) Land use and terrain data were developed using the North American 30-arc-second data

3.3 *CALPUFF*

The CALPUFF modeling will use Version 6.112. This protocol generally follows the recommendation of the IWAQM and FLAG guidance documents. Details of the parameter settings in CALPUFF are provided in Appendix D; however, the major features are summarized below:

1) The three-year CALMET input files will be developed by Geomatrix and be provided as input-ready to CALPUFF.

2) The BART exemption modeling will examine the visibility impairment on Class I areas within 300km of each single source. Where BART-eligible sources are grouped or where their emissions could collectively impair visibility in a Class I area, the exemption modeling will also group these sources in order to examine their cumulative impact. The computational modeling domain will be sufficient to include all Class I areas within a 300km radius of a source or sources.

3) Pasquill-Gifford Dispersion coefficients will be used.

4) MESOPUFF-II chemistry algorithm will be used.

5) Building downwash will be ignored for cases with source-to-receptor distances greater than 50km, as recommended by the Federal Land Managers (FLMs) (US Fish and Wildlife, National Park Service, and U.S. Forest Service) who were consulted for this protocol.

6) Puff splitting will not be used, following the recommendations of the FLMs.

7) Source elevations that will be entered in CALPUFF will not use actual elevations but will be based on the modeled terrain surface used in CALMET for developing wind fields. The same algorithm in CALMET that determines the elevations of the observational stations will be used to make this calculation. These modified source elevations will be provided to the BART eligible sources.

3.3.1 Emissions

Section 2.4 above presents the emissions and stack data that is required from the facilities. This section only discusses the emissions estimates needed in CALPUFF.

Primary emission, species will include the input species PM, SO_2, SO_4, and NO_x; and the additional modeled species HNO_3 and NO_3. Emissions of H_2SO_4 will be included, if known, and used for estimation of SO_4 emissions. SO_2 emissions will be reviewed to ensure "double-counting" is avoided.

The primary PM species will be treated as follows:

- BART-eligible sources are required to include both filterable and condensable fractions of PM.

  Filterable:
  Elemental Carbon (EC) (<2.5 μm)
  PM Fine (PMF) (<2.5 μm)
  PM Coarse (PMC) (2.5 – 10 μm)
  Condensable:
  Organic Carbon (SOA)
  Inorganic Aerosol (SO_4)
  Non-SO_4 inorganic aerosol

- The condensable fraction will be treated as primary emissions in the CALPUFF input file and assumed to be 100% in the $PM_{2.5}$ fraction (see NPS Web site listed below).

The states will work with the individual BART-eligible sources to develop appropriate PM speciation and size fractions. The following information sources may be used in the development of the speciation and fractions:

- U.S. National Park Service (NPS) – the NPS has developed both PM speciation and size fractions for several source categories. The information is located at http://www2.nature.nps.gov/air/Permits/ect/index.cfm

- U.S. EPA – the EPA has developed generic PM speciation for all source categories located at http://www.epa.gov/ttn/chief/emch/speciation/.

- If size fraction is not known, the following default values, based on information in the CALPUFF User's Guide, CALPUFF GUI, and AP-42 will be used:

Pollutant	Mean diameter	Standard deviation
SO_4, NO_3, PMF, SOA, EC	0.50 microns	1.5
PMC	5.00 microns	1.5

3.3.2 Ozone Background

Due to the number of BART-eligible sources and Class I areas being analyzed, a single value of 60ppb (parts per billion) is used for all months and all three states. This value was determined based on a review of available ozone data for Idaho, Oregon, and Washington.

3.3.3 Ammonia Background

As with the ozone background, a single value of 17ppb is used for the ammonia background. This value is supported by measurements made in 1996 – 1997 at Abbotsford in the Frazier River Valley of British Columbia. This value has also been commonly used as background for Prevention of Significant Deterioration modeling in the Pacific Northwest and will ensure that for BART exemption modeling, conditions are not ammonia limited. It is recognized that ammonia values may be lower in Class I areas; however, the BART analysis must account for transport through ammonia-rich areas.

3.3.4 Receptor Locations

Visibility impacts will be computed at all Class I areas and the Columbia River Gorge Scenic Area if they lie within a 300-km radius of the BART eligible source. The geolocations of the receptor points and their elevations for the Class I areas that will be used in the modeling are available for download from the National Park Service Web site at http://www2.nature.nps.gov/air/Maps/Receptors/index.cfm>.

Receptor points and elevations for the Columbia River Gorge Scenic Area will be provided by Oregon and Washington.

3.4 *CALPOST and VISIBILITY POST-PROCESSING*

The following assumptions will be used in CALPOST and POSTUTIL to calculate the visibility impairment:

1) For the visibility calculation, Method 6 will be employed. This method uses monthly average relative humidity and f(RH) values for each Class I area as provided in Appendix B, which are based on the EPA Guidance for Regional Haze analysis (EPA 2003).

2) Particulate species for the visibility analysis will include SO_4, NO_3, EC, OC, PMF, and PMC, as reported in the CALPOST output files.

3) POSTUTIL will not be used to speciate modeled PM_{10} concentrations, as PM_{10} will be speciated into its components (PMF, PMC, SOA, EC, SO_4) and entered as primary emissions in CALPUFF. In addition, HNO_3/NO_3 partition option in POSTUTIL will not be used for ammonia limiting.

4) Natural background extinction calculations will use the 20% best days for each Class I area in the three-state region. The natural background for the 20% best days has been refined from that which is in "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule" (EPA 2003). The extinction coefficients for the 20% best days have been calculated following the approach taken in the Draft Montana BART modeling protocol. This procedure uses the haze index (HI) in deciviews at the 10th percentile (median of the 20% best days) and an activity factor that is calculated for each Class I area. Tables providing the monthly f(RH) and 20% best days coefficients are provided in Appendix B, and are based on data from EPA (2003). For the exemption modeling, the Rayleigh scattering value will be 10 Mm-1 for all Class I areas.

    - The 98th percentile value will be calculated for all BART-eligible sources at each mandatory Class I area.

5) The CALPOST "LST" output files will be used to determine the 98th percentile of visibility impairment for each receptor in CLASS I areas.

6) The contribution threshold has the implied level of precision equal to the level of precision reported by CALPOST. Therefore, the 98th percentile value will be reported to three decimal places.

4. Interpretation of Results

The change in visibility impairment for the BART exemption modeling is based on the increase in HI from a BART-eligible source or sources relative to natural background, defined as the 20% best visibility days for each Class I area. This definition of natural background is consistent with the intent of the BART guideline (Federal Register Vol. 70, No. 128, pf 39125).

The U.S. EPA recommends using the 98th percentile value from the distribution of values containing the highest modeled delta-deciview (Δdv) value for each day of the simulation from all modeled receptors at a given Class I area. The 98th percentile Δdv value will be determined in the following ways:

- The 8th highest value for each year modeled
- The 22nd highest value for the 3-year modeling period

Both methods will be used and the highest value of the two will be compared to the contribution threshold ($\Delta dv \geq 0.5$ dv). If there are more than 7 days with values greater than the contribution threshold in any single meteorological year for any Class I area, or more than 21 days in three years, then the source is considered Subject-to-BART.

5. References

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Appendix A

Mandatory Class I Federal Areas

and

Columbia River Gorge Scenic Area

Figure A-1

Map of BART-Eligible Sources and Class I Areas

Posted on Idaho DEQ's Regional Haze BART Website

http://www.deq.idaho.gov/air/prog_issues/pollutants/haze_bart.cfm.

Table 1. Federal Mandatory Class I Areas.

Class I Area	Federal Land Manager
Idaho	
Craters of the Moon National Monument	Park Service
Hells Canyon Wilderness	Forest Service
Sawtooth Wilderness	Forest Service
Selway-Bitterroot Wilderness	Forest Service
Yellowstone National Park	Park Service
Oregon	
Crater Lake National Park	Park Service
Diamond Peak Wilderness	Forest Service
Eagle Cap Wilderness	Forest Service
Gearhart Mountain Wilderness	Forest Service
Hells Canyon Wilderness	Forest Service
Kalmiopsis Wilderness	Forest Service
Three Sisters Wilderness	Forest Service
Mount Hood Wilderness	Forest Service
Mount Jefferson Wilderness	Forest Service
Mount Washington Wilderness	Forest Service
Mountain Lakes Wilderness	Forest Service
Strawberry Mountain Wilderness	Forest Service
Washington	
Alpine Lakes Wilderness	Forest Service
Goat Rocks Wilderness	Forest Service
Glacier Peak Wilderness	Forest Service
Mount Adams Wilderness	Forest Service
Mount Ranier National Park	Park Service
North Cascades National Park	Park Service
Olympic National Park	Park Service
Pasayten Wilderness	Forest Service
Neighboring States	
Anaconda-Pintler Wilderness (MT)	Forest Service
Bob Marshall Wilderness (MT)	Forest Service
Cabinet Mountains Wilderness (MT)	Forest Service
Gates of the Mountain Wilderness (MT)	Forest Service
Glacier National Park (MT)	Park Service
Missions Mountain Wilderness (MT)	Forest Service
Scapegoat Wilderness (MT)	Forest Service
Red Rock Lakes Refuge (MT)	Fish & Wildlife Service
Bridger Wilderness (WY)	Forest Service
Fitzpatrick Wilderness (WY)	Forest Service
Grand Teton National Park (WY)	Park Service
North Absaroka Wilderness (WY)	Forest Service
Teton Wilderness (WY)	Forest Service
Washakie Wilderness (WY)	Forest Service
Caribous Wilderness (CA)	Forest Service
Lassen Volcanic National Park (CA)	Park Service

Table 1. Federal Mandatory Class I Areas.

Class I Area	Federal Land Manager
Lava Beds National Monument (CA)	Park Service
Marble Mountain Wilderness (CA)	Forest Service
Redwood National Park (CA)	Park Service
South Warner Wilderness (CA)	Forest Service
Thousand Lakes Wilderness (CA)	Forest Service
Yolla Bolly-Middle Eel Wilderness (CA)	Forest Service
Jarbridge Wilderness (NV)	Forest Service

Hells Canyon is located in Idaho and Oregon.
Yellowstone is located in Idaho, Montana and Wyoming.

Appendix B

Natural Visibility Background

and

Monthly Relative Humidity f(RH)

Adjustment to speciated particulate (Western States) to reflect 20% Best Visibility Days conditions

Monthly f(RH) are from *Appendix A of Draft Guidance for Estimating Natural Visibility Conditions under the RHR (Sept. 2003)*.

Background extinction coefficients (20% Best Days) have been calculated using Annual Avg bext, Best 20% bext, and activity factors.

		CALPOST Input Group 2 Monthly extinction coefficients for hygroscopic species (RHFAC)												CALPOST Input Group 2 Background extinction coefficients (20% Best Days)					
Class I Area	State	Jan. f(RH)	Feb. f(RH)	Mar. f(RH)	Apr. f(RH)	May f(RH)	June f(RH)	July f(RH)	Aug. f(RH)	Sep. f(RH)	Oct. f(RH)	Nov. f(RH)	Dec. f(RH)	BKSO4 ug/m3	BKNO3 ug/m3	BKPMC ug/m3	BKOC ug/m3	SOIL ug/m3	BKEC ug/m3
CaribouWilderness	CA	3.69	3.13	2.83	2.45	2.37	2.17	2.07	2.13	2.20	2.38	3.01	3.41	0.048	0.040	1.20	0.188	0.200	0.008
LassenVolcanic	CA	3.81	3.19	2.91	2.53	2.42	2.19	2.09	2.14	2.23	2.43	3.13	3.53	0.048	0.040	1.21	0.189	0.201	0.008
Lava Beds NP	CA	3.98	3.36	3.07	2.70	2.62	2.43	2.31	2.34	2.42	2.72	3.52	3.81	0.050	0.042	1.26	0.197	0.210	0.008
MarbleMountain	CA	4.44	3.79	3.74	3.33	3.37	3.24	3.18	3.19	3.24	3.37	4.12	4.15	0.052	0.043	1.30	0.204	0.217	0.009
RedwoodNP	CA	4.42	3.91	4.56	3.91	4.50	4.70	4.86	4.72	4.31	3.66	3.81	3.40	0.054	0.045	1.34	0.210	0.224	0.009
SouthWarner	CA	3.62	3.08	2.72	2.35	2.29	2.12	1.90	1.92	1.97	2.30	3.05	3.44	0.048	0.040	1.21	0.190	0.202	0.008
ThousandLakes	CA	3.81	3.19	2.91	2.53	2.42	2.19	2.09	2.14	2.23	2.43	3.13	3.53	0.048	0.040	1.21	0.190	0.202	0.008
Yolla Bolly Middle Eel Wilderr	CA	3.95	3.35	3.14	2.76	2.68	2.47	2.44	2.50	2.56	2.70	3.31	3.62	0.049	0.041	1.24	0.194	0.206	0.008
Craters of the Moon	ID	3.13	2.74	2.28	2.02	2.01	1.81	1.43	1.42	1.57	1.97	2.77	3.04	0.046	0.038	1.15	0.180	0.192	0.008
HellsCanyon	ID	3.70	3.12	2.51	2.17	2.12	2.00	1.63	1.58	1.79	2.41	3.45	3.87	0.048	0.040	1.21	0.190	0.202	0.008
SawtoothWilderness	ID	3.34	2.87	2.32	2.01	2.00	1.84	1.43	1.40	1.50	1.96	2.94	3.31	0.046	0.039	1.16	0.182	0.193	0.008
Selway-BitterrootWilderness	ID	3.50	3.02	2.59	2.34	2.36	2.31	1.93	1.86	2.09	2.55	3.30	3.50	0.048	0.040	1.21	0.190	0.202	0.008
Anaconda-PintlerWilderness	MT	3.32	2.88	2.54	2.35	2.36	2.31	1.96	1.88	2.10	2.52	3.15	3.29	0.048	0.040	1.20	0.188	0.200	0.008
BobMarshall	MT	3.57	3.10	2.77	2.59	2.66	2.70	2.34	2.23	2.58	2.92	3.47	3.54	0.049	0.041	1.22	0.191	0.203	0.008
CabinetMountains	MT	3.81	3.27	2.85	2.61	2.66	2.68	2.30	2.18	2.56	2.98	3.70	3.86	0.050	0.041	1.24	0.195	0.207	0.008
Gates of the Mountain	MT	2.89	2.57	2.42	2.30	2.30	2.27	2.03	1.94	2.12	2.41	2.75	2.81	0.047	0.039	1.18	0.185	0.197	0.008
GlacierNP	MT	4.01	3.47	3.18	3.06	3.24	3.39	2.76	2.60	3.19	3.45	3.82	3.89	0.051	0.043	1.28	0.200	0.213	0.009
MissionMountain	MT	3.60	3.13	2.73	2.52	2.60	2.62	2.27	2.19	2.50	2.87	3.51	3.59	0.049	0.041	1.23	0.193	0.205	0.008
RedRock Lakes	MT	2.73	2.46	2.28	2.12	2.10	1.91	1.67	1.58	1.77	2.07	2.56	2.68	0.046	0.039	1.16	0.181	0.193	0.008
ScapegoatWilderness	MT	3.19	2.81	2.57	2.43	2.45	2.44	2.14	2.04	2.28	2.61	3.08	3.14	0.048	0.040	1.20	0.188	0.200	0.008
Crater Lake NP	OR	4.57	3.92	3.68	3.36	3.22	2.99	2.84	2.87	3.05	3.59	4.57	4.56	0.053	0.044	1.32	0.206	0.219	0.009
DiamondPeak	OR	4.52	3.96	3.64	3.66	3.16	3.12	2.90	2.93	3.05	3.67	4.55	4.57	0.053	0.044	1.33	0.208	0.222	0.009
Eagle Cap	OR	3.77	3.16	2.47	2.10	2.04	1.87	1.61	1.56	1.61	2.25	3.44	3.97	0.049	0.041	1.22	0.191	0.203	0.008
Gearhart Mountain	OR	3.96	3.38	3.06	2.75	2.65	2.48	2.28	2.30	2.38	2.84	3.65	3.84	0.050	0.042	1.25	0.196	0.208	0.008
Kalmiopsis Wilderness	OR	4.54	3.90	3.83	3.45	3.46	3.32	3.20	3.20	3.29	3.56	4.39	4.32	0.053	0.044	1.32	0.206	0.219	0.009
Mount Hood	OR	4.29	3.81	3.46	3.87	2.95	3.15	2.85	3.00	3.10	3.86	4.53	4.55	0.053	0.044	1.33	0.209	0.222	0.009
Mount Jefferson	OR	4.41	3.90	3.56	3.74	3.07	3.11	2.89	2.91	3.03	3.78	4.55	4.54	0.054	0.045	1.34	0.210	0.223	0.009
Mountain Lakes	OR	4.29	3.62	3.32	2.98	2.86	2.64	2.49	2.50	2.64	3.10	4.12	4.26	0.051	0.043	1.28	0.201	0.214	0.009
MountWashington	OR	4.44	3.93	3.58	3.73	3.09	3.11	2.98	2.91	3.02	3.76	4.56	4.56	0.054	0.045	1.36	0.213	0.227	0.009
StrawberryMountain	OR	3.89	3.33	2.75	2.93	2.27	2.39	1.98	1.97	1.87	2.63	3.69	4.07	0.050	0.042	1.26	0.197	0.210	0.008
ThreeSisters	OR	4.47	3.95	3.61	3.72	3.11	3.11	3.00	2.91	3.03	3.79	4.60	4.57	0.054	0.045	1.35	0.212	0.226	0.009
AlpineLakes	WA	4.25	3.79	3.47	3.90	2.93	3.22	2.92	3.12	3.25	3.91	4.47	4.51	0.054	0.045	1.35	0.212	0.225	0.009
GlacierPeak	WA	4.16	3.72	3.42	3.75	2.91	3.16	2.88	3.14	3.33	3.90	4.42	4.43	0.054	0.045	1.34	0.210	0.223	0.009
GoatRocks	WA	4.25	3.75	3.36	4.24	2.83	3.38	3.03	3.19	3.07	3.77	4.42	4.55	0.054	0.045	1.34	0.210	0.224	0.009
Mount Adams	WA	4.29	3.80	3.44	4.40	2.92	3.49	3.12	3.27	3.13	3.86	4.49	4.56	0.053	0.044	1.33	0.209	0.222	0.009
MountRainier	WA	4.42	3.96	3.64	4.65	3.06	3.69	3.30	3.50	3.40	4.11	4.66	4.66	0.055	0.045	1.36	0.214	0.227	0.009
NorthCascades NP	WA	4.10	3.69	3.43	3.74	2.93	3.20	2.93	3.23	3.45	3.93	4.39	4.38	0.053	0.044	1.33	0.209	0.222	0.009
OlympicNP	WA	4.51	4.08	3.82	4.08	3.17	3.46	3.12	3.48	3.71	4.38	4.83	4.75	0.054	0.045	1.36	0.213	0.226	0.009
PasaytenWilderness	WA	4.17	3.72	3.41	3.72	2.89	3.16	2.88	3.15	3.32	3.86	4.42	4.46	0.053	0.044	1.33	0.208	0.222	0.009
BridgerWilderness	WY	2.52	2.35	2.34	2.19	2.10	1.80	1.50	1.49	1.74	2.00	2.44	2.42	0.046	0.038	1.14	0.178	0.190	0.008
FitzpatrickWilderness	WY	2.51	2.33	2.24	2.13	2.09	1.80	1.51	1.46	1.73	1.98	2.39	2.44	0.046	0.038	1.14	0.179	0.190	0.008
Grand Teton NP	WY	2.62	2.39	2.24	2.10	2.06	1.79	1.52	1.47	1.72	2.00	2.43	2.55	0.046	0.038	1.14	0.178	0.190	0.008
NorthAbsaroka	WY	2.43	2.27	2.24	2.17	2.14	1.93	1.69	1.56	1.76	2.04	2.35	2.40	0.046	0.038	1.14	0.178	0.190	0.008
TetonWilderness	WY	2.53	2.35	2.24	2.12	2.10	1.85	1.59	1.51	1.74	2.02	2.40	2.48	0.046	0.038	1.14	0.178	0.190	0.008
WashakieWilderness	WY	2.50	2.34	2.23	2.12	2.11	1.84	1.56	1.49	1.75	2.00	2.38	2.46	0.046	0.038	1.14	0.179	0.190	0.008
YellowstoneNP	WY	2.54	2.36	2.27	2.16	2.15	1.94	1.69	1.59	1.79	2.08	2.45	2.51	0.046	0.038	1.15	0.180	0.192	0.008
JarbridgeWilderness	NV	2.95	2.60	2.08	2.12	2.21	2.17	1.58	1.40	1.35	1.63	2.44	2.80	0.046	0.038	1.14	0.179	0.190	0.008
Columbia River Gorge	OR-WA	5.03	5.03	2.59	2.59	2.59	2.11	2.11	2.11	3.51	3.51	3.51	5.03	0.569	0.231	4.85	1.05	0.217	0.205

Appendix C

CALMET Parameter Values

Appendix C
CALMET Parameter Values

Recommended CALMET parameters chosen by the Region 10 states for use in BART modeling				
Input Group	**Variable**	**Description**	**Default Value**	**Recommended Value**
0	DIADAT	Input file: preprocessed surface temperature data (DIAG.DAT)	User Defined	
0	GEODAT	Input file: Geophysical data (GEO.DAT)	User Defined	User Define
0	LCFILES	Convert file name to lower case	User Defined	
0	METDAT	Output file (CALMET.DAT)	User Defined	
0	METLST	Output file (CALMET.LST)	User Defined	
0	MM4DAT	Input file: MM4 data (MM4.DAT)	User Defined	
0	NOWSTA	Input files: Names of NOWSTA overwater stations	User Defined	0
0	NUSTA	Number of upper air data sites	User Defined	0
0	PACDAT	Output file: in Mesopuff II format (PACOUT.DAT)	User Defined	
0	PRCDAT	Input file: Precipitation data (PRECIP.DAT)	User Defined	
0	PRGDAT	Input file: CSUMM prognostic wind data (PROG.DAT)	User Defined	
0	SEADAT	Input files: Names of NOWSTA overwater stations (SEAn.DAT)	User Defined	
0	SRFDAT	Input file: Surface data (SURF.DAT)	User Defined	
0	TSTFRD	Output file (TEST.FRD)	User Defined	
0	TSTKIN	Output file (TEST.KIN)	User Defined	
0	TSTOUT	Output file (TEST.OUT)	User Defined	
0	TSTPRT	Output file (TEST.PRT)	User Defined	
0	TSTSLP	Output file (TEST.SLP)	User Defined	
0	UPDAT	Input files: Names of NUSTA upper air data files (UPn.DAT)	UPn.DAT	
0	WTDAT	Input file: Terrain weighting factors (WT.DAT)	User Defined	
1	CLDDAT	Input file: Cloud data (CLOUD.DAT)	User Defined	Not used
1	IBDY	Beginning day	User Defined	
1	IBHR	Beginning hour	User Defined	
1	IBMO	Beginning month	User Defined	
1	IBTZ	Base time zone	User Defined	8
1	IBYR	Beginning year	User Defined	
1	IRLG	Number of hours to simulate	User Defined	User Define
1	IRTYPE	Output file type to create (must be 1 for CALPUFF)	1	1
1	ITEST	Flag to stop run after Setup Phase	2	2
1	LCALGRD	Are w-components and temperature needed?	T	T
2	DATUM	WGS-G, NWS-27, NWS-84, ESR-S,…		NWS84
2	DGRIDKM	Grid spacing	User Defined	4
2	IUTMZN	UTM Zone	User Defined	User Define
2	LLCONF	When using Lambert Conformal map coordinates - rotate winds from true north to map north?	F	F
2	NX	Number of east-west grid cells	User Defined	373
2	NY	Number of north-south grid cells	User Defined	316
2	NZ	Number of vertical layers	User Defined	10
2	RLAT0	Latitude used if LLCONF = T	User Defined	49.0N
2	RLON0	Longitude used if LLCONF = T	User Defined	121.0W
2	XLAT0	Southwest grid cell latitude	User Defined	User Define
2	XLAT1	Latitude of 1st standard parallel	User Defined	30
2	XLAT2	Latitude of 2nd standard parallel	User Defined	60
2	XORIGKM	Southwest grid cell X coordinate	User Defined	-572
2	YLON0	Southwest grid cell longitude	User Defined	-956
2	YORIGKM	Southwest grid cell Y coordinate	User Defined	User Define
2	ZFACE	Vertical cell face heights (NZ+1 values)	User Defined	0,20,40,65,120,200,400, 700,1200,2200,4000
3	IFORMO	Format of unformatted file (1 for CALPUFF)	1	1
3	LSAVE	Save met. data fields in an unformatted file?	T	T
4	ICLOUD	Is cloud data to be input as gridded fields? (0 = No)	0	0
4	IFORMC	Format of cloud data (2 = formatted)	2	2
4	IFORMP	Format of precipitation data (2 = formatted)	2	2
4	IFORMS	Format of surface data (2 = formatted)	2	2

Recommended CALMET parameters chosen by the Region 10 states for use in BART modeling				
Input Group	Variable	Description	Default Value	Recommended Value
4	NOOBS	Use or non-use of surface, overwater, upper observations		1
4	NPSTA	Number of stations in PRECIP.DAT	User Defined	-1
4	NSSTA	Number of stations in SURF.DAT file	User Defined	115
5	ALPHA	Empirical factor triggering kinematic effects	0.1	0.1
5	BIAS	Surface/upper-air weighting factors (NZ values)	NZ*0	NZ*0
5	CRITFN	Critical Froude number	1	1
5	DIVLIM	Maximum acceptable divergence	5.00E-06	5.00E-06
5	FEXTR2	Multiplicative scaling factor for extrap surface obs to uppr layrs	NZ*0.0	
5	ICALM	Extrapolate surface calms to upper layers? (0 = No)	0	0
5	IDIOPT1	Compute temperatures from observations (0 = True)	0	0
5	IDIOPT2	Compute domain-average lapse rates? (0 = True)	0	0
5	IDIOPT3	Compute internally inital guess winds? (0 = True)	0	0
5	IDIOPT4	Read surface winds from SURF.DAT? (0 = True)	0	0
5	IDIOPT5	Read aloft winds from UPn.DAT? (0 = True)	0	0
5	IEXTRP	Extrapolate surface winds to upper layers? (-4 = use similarity theory and ignore layer 1 of upper air station data)	-4	-1
5	IFRADJ	Adjust winds using Froude number effects? (1 = Yes)	1	1
5	IKINE	Adjust winds using kinematic effects? (1 = Yes)	0	0
5	IOBR	Use O'Brien procedure for vertical winds? (0 = No)	0	0
5	IPROG	Using prognostic or MM-FDDA data? (0 = No)	0	14
5	ISLOPE	Compute slope flows? (1 = Yes)	1	1
5	ISTEPPG	Timestep (hours) of the prognostic model input data	1	1
5	ISURFT	Surface station to use for surface temperature (between 1 and NSSTA)	User Defined	98
5	IUPT	Station for lapse rates (between 1 and NUSTA)	User Defined	1
5	IUPWND	Upper air station for domain winds (-1 = 1/r**2 interpolation of all stations)	-1	-1
5	IWFCOD	Generate winds by diagnostic wind module? (1 = Yes)	1	1
5	KBAR	Level (1 to NZ) up to which barriers apply	NZ	10
5	LLBREZE	Use Lake Breeze module	F	F
5	LVARY	Use varying radius to develop surface winds?	F	F
5	METBXID	Station IDs in the region	User Defined	
5	NBAR	Number of Barriers to interpolation	User Defined	0
5	NBOX	Number of Lake Breeze regions	User Defined	0
5	NINTR2	Max number of stations for interpolations (NA values)	99	99
5	NITER	Max number of passes in divergence minimization	50	50
5	NLB	Number of stations in region	User Defined	0
5	NSMTH	Number of passes in smoothing (NZ values)	2, 4*(NZ-1)	1,2,2,3,3,4,4,4,4,4
5	R1	Relative weight at surface of Step 1 field and obs	User Defined	1.00E-06
5	R2	Relative weight aloft of Step 1 field and obs	User Defined	1.00E-06
5	RMAX1	Max surface over-land extrapolation radius (km)	User Defined	200
5	RMAX2	Max aloft over-land extrapolation radius (km)	User Defined	200
5	RMAX3	Maximum over-water extrapolation radius (km)	User Defined	200
5	RMIN	Minimum extrapolation radius (km)	0.1	0.1
5	RMIN2	Distance (km) around an upper air site where vertical extrapolation is excluded (Set to -1 if IEXTRP = ±4)	4	-1
5	RPROG	Weighting factor for CSUMM prognostic wind data	User Defined	0
5	TERRAD	Radius of influence of terrain features (km)	User Defined	12
5	XBBAR	X coordinate of Beginning of each barrier	User Defined	0
5	XBCST	X Point defining the coastline (straight line)	User Defined	0
5	XEBAR	X coordinate of Ending of each barrier	User Defined	0
5	XECST	X Point	User Defined	0
5	XG1	X Grid line 1 defining region of interest	User Defined	0
5	XG2	X Grid line 2	User Defined	0
5	YBBAR	Y coordinate of Beginning of each barrier	User Defined	0
5	YBCST	Y Point	User Defined	0
5	YEBAR	Y coordinate of Ending of each barrier	User Defined	0
5	YECST	Y Point	User Defined	0

Recommended CALMET parameters chosen by the Region 10 states for use in BART modeling				
Input Group	**Variable**	**Description**	**Default Value**	**Recommended Value**
5	YG1	Y Grid line 1	User Defined	0
5	YG2	Y Grid Line 2	User Defined	0
5	ZUPT	Depth of domain-average lapse rate (m)	200	200
5	ZUPWND	Bottom and top of layer for 1st guess winds (m)	1, 1000	1.,1000.
6	CONSTB	Neutral mixing height B constant	1.41	1.41
6	CONSTE	Convective mixing height E constant	0.15	0.15
6	CONSTN	Stable mixing height N constant	2400	2400
6	CONSTW	Over-water mixing height W constant	0.16	0.16
6	CUTP	Minimum cut off precip rate (mm/hr)	0.01	0.01
6	DPTMIN	Minimum capping potential temperature lapse rate	0.001	0.001
6	DSHELF	Coastal/shallow water length scale	0	0
6	DZZI	Depth for computing capping lapse rate (m)	200	200
6	FCORIOL	Absolute value of Coriolis parameter	1.00E-04	1.00E-04
6	HAFANG	Half-angle for looking upwind (degrees)	30	30
6	IAVET	Conduct spatial averaging of temperature? (1 = True)	1	1
6	IAVEZI	Spatial averaging of mixing heights? (1 = True)	1	1
6	ICOARE	Overwater surface fluxes method and parameters	10	10
6	ICOOL	COARE cool skin layer computation	0	0
6	ILEVZI	Layer to use in upwind averaging (between 1 and NZ)	1	1
6	ILUOC3D	Land use category ocean in 3D.DAT datasets	16	16
6	IMIXH	Method to compute the convective mixing height	1	1
6	IRAD	Form of temperature interpolation (1 = 1/r)	1	1
6	IRHPROG	3D relative humidity from observations or from prognostic data	0	1
6	ITPROG	3D temps from obs or from prognostic data?	0	2
6	ITWPROG	Option for overwater lapse rates used in convective mixing height growth	0	2
6	IWARM	COARE warm layer computation	0	0
6	JWAT1	Beginning landuse type defining water	999	55
6	JWAT2	Ending landuse type defining water	999	55
6	MNMDAV	Max averaging radius (number of grid cells)	1	1
6	NFLAGP	Method for precipitation interpolation (2 = 1/r**2)	2	2
6	NUMTS	Max number of stations in temperature interpolations	5	10
6	SIGMAP	Precip radius for interpolations (km)	100	12
6	TGDEFA	Default over-water capping lapse rate (K/m)	-0.0045	-0.0045
6	TGDEFB	Default over-water mixed layer lapse rate (K/m)	-0.0098	-0.0098
6	THRESHL	Threshold buoyancy flux required to sustain convective mixing height growth overland	0.05	0.05
6	THRESHW	Threshold buoyancy flux required to sustain convective mixing height growth overwater	0.05	0.05
6	TRADKM	Radius of temperature interpolation (km)	500	500
6	ZIMAX	Maximum over-land mixing height (m)	3000	3000
6	ZIMAXW	Maximum over-water mixing height (m)	3000	3000
6	ZIMIN	Minimum over-land mixing height (m)	50	50
6	ZIMINW	Minimum over-water mixing height (m)	50	50

Appendix D

CALPUFF Parameter Values

Appendix D
CALPUFF Parameter Values

Recommended CALPUFF Parameters chosen by EPA Region 10 states for use in BART modeling.

Input Group	Group Description	Sequence	Variable	Description	Default Value[a]	Recommended Value
1	Run Control	1	METRUN	Do we run all periods (1) or a subset (0)?	0	
1		2	IBYR	Beginning year	User Defined	
1		3	IBMO	Beginning month	User Defined	
1		4	IBDY	Beginning day	User Defined	
1		5	IBHR	Beginning hour	User Defined	
1		5	IRLG	Length of run (hours)	User Defined	
1		5	NSECDT	Length of modeling time step (seconds)	3600	3600
1		6	NSPEC	Number of species modeled (for MESOPUFF II chemistry)	5	
1		7	NSE	Number of species emitted	3	
1		8	ITEST	Flag to stop run after Setup Phase	2	
1		9	MRESTART	Restart options (0 = no restart) allows splitting runs into smaller segments	0	
1		10	NRESPD	Number of periods in Restart	0	
1		11	METFM	Format of input meteorology (1 = CALMET, 2 = ISC)	1	
1		12	AVET	Averaging time lateral dispersion parameters (minutes)	60	60
1		13	PGTIME	PG Averaging time	60	60
2	Tech Options	1	MGAUSS	Near-field vertical distribution (1 = Gaussian)	1	1
2		2	MCTADJ	Terrain adjustments to plume path (3 = Plume path)	3	3
2		3	MCTSG	Do we have subgrid hills? (0 = No) allows CTDM-like treatment for subgrid scale hills	0	0
2		4	MSLUG	Near-field puff treatment (0 = No slugs)	0	0
2		5	MTRANS	Model transitional plume rise? (1 = Yes)	1	1
2		6	MTIP	Treat stack tip downwash? (1 = Yes)	1	1
2		7	MBDW	Method to simulate downwash (1=ISC,2=PRIME)		not used
2		8	MSHEAR	Treat vertical wind shear? (0 = No)	0	0
2		9	MSPLIT	Allow puffs to split? (0 = No)	0	0
2		10	MCHEM	MESOPUFF-II Chemistry? (1 = Yes)	1	1
2		11	MAQCHEM	Aqueous phase transformation	0	0
2		12	MWET	Model wet deposition? (1 = Yes)	1	1
2		13	MDRY	Model dry deposition? (1 = Yes)	1	1
2		13	MTILT	Plume Tilt (gravitational settling)	0	0
2		14	MDISP	Method for dispersion coefficients (2=micromet,3 = PG)	3	3
2		15	MTURBVW	Turbulence characterization? (Only if MDISP = 1 or 5)	3	3
2		16	MDISP2	Backup coefficients (Only if MDISP = 1 or 5)	3	3
2		16	MTAULY	Method for Sigma y Lagrangian timescale	0	0
2		16	MTAUADV	Method for Advective-Decay timescale for Turbulence	0	0
2		16	MCTURB	Method to compute sigma v,w using micromet variables	1	1
2		17	MROUGH	Adjust PG for surface roughness? (0 = No)	0	0
2		18	MPARTL	Model partial plume penetration? (0 = No)	1	1
2		19	MTINV	Elevated inversion strength (0 = compute from data)	0	0
2		20	MPDF	Use PDF for convective dispersion? (0 = No)	0	0
2		21	MSGTIBL	Use TIBL module? (0 = No) allows treatment of subgrid scale coastal areas	0	0
2		22	MBCON	Boundary conditions modeled	0	0
2		23	MFOG	Configure for FOG model output	0	0
2		24	MREG	Regulatory default checks? (1 = Yes)	1	1

Recommended CALPUFF Parameters chosen by EPA Region 10 states for use in BART modeling.

Input Group	Group Description	Sequence	Variable	Description	Default Value[a]	Recommended Value
3	Species List	1	CSPECn	Names of species modeled (for MESOPUFF II must be SO2-SO4-NOX-HNO3-NO3)	User Defined	
3		2	Specie Names	Manner species will be modeled	User Defined	
3		3	Specie Groups	Grouping of species if any	User Defined	
3		4	CGRUP			
3		5	CGRUP			
4	MapProjection		XLAT1	Latitude of 1st standard parallel		
4			XLAT2	Latitude of 2nd standard parallel		
4			DATUM			NWS84
4		1	NX	Number of east-west grids of input meteorology	User Defined	
4		2	NY	Number of north-south grids of input meteorology	User Defined	
4		3	NZ	Number of vertical layers of input meteorology	User Defined	
4		4	DGRIDKM	Meteorology grid spacing (km)	User Defined	
4		5	ZFACE	Vertical cell face heights of input meteorology	User Defined	
4		6	XORIGKM	Southwest corner (east-west) of input User	Defined meteorology	
4		7	YORIGIM	Southwest corner (north-south) of input User	Defined meteorology	
4		8	IUTMZN	UTM zone	User Defined	
4		9	XLAT	Latitude of center of meteorology domain	User Defined	
4		10	XLONG	Longitude of center of meteorology domain	User Defined	
4		11	XTZ	Base time zone of input meteorology	User Defined	
4		12	IBCOMP	Southwest X-index of computational domain	User Defined	
4		13	JBCOMP	Southwest Y-index of computational domain	User Defined	
4		14	IECOMP	Northeast X-index of computational domain	User Defined	
4		15	JECOMP	Northeast Y-index of computational domain	User Defined	
4		16	LSAMP	Use gridded receptors? (T = Yes)	F	F
4		17	IBSAMP	Southwest X-index of receptor grid	User Defined	
4		18	JBSAMP	Southwest Y-index of receptor grid	User Defined	
4		19	IESAMP	Northeast X-index of receptor grid	User Defined	
4		20	JESAMP	Northeast Y-index of receptor grid	User Defined	
4		21	MESHDN	Gridded recpetor spacing = DGRIDKM/MESHDN	1	
5	Output Options	1	ICON	Output concentrations? (1 = Yes)	1	1
5		2	IDRY	Output dry deposition flux? (1 = Yes)	1	1
5		3	IWET	Output west deposition flux? (1 = Yes)	1	1
5		4	IT2D	2D Temperature	0	0
5		5	IRHO	2D Density	0	0
5		6	IVIS	Output RH for visibility calculations (1 = Yes)	1	1
5		7	LCOMPRS	Use compression option in output? (T = Yes)	T	T
5		8	ICPRT	Print concentrations? (0 = No)	0	0
5		9	IDPRT	Print dry deposition fluxes (0 = No)	0	0
5		10	IWPRT	Print wet deposition fluxes (0 = No)	0	0
5		11	ICFRQ	Concentration print interval (1 = hourly)	1	24
5		12	IDFRQ	Dry deposition flux print interval (1 = hourly)	1	24
5		13	IWFRQ	West deposition flux print interval (1 = hourly)	1	24
5		14	IPRTU	Print output units (1 = g/m**3; g/m**2/s; 3 = ug/m3, ug/m2/s)	1	3
5		15	IMESG	Status messages to screen? (1 = Yes)	1	2
5		16	LDEBUG	Turn on debug tracking? (F = No)	F	F
5		16	IPFDEB	First puff to track	1	1
5		17	NPFDEB	(Number of puffs to track)	(1)	1
5		18	NN1	(Met. Period to start output)	(1)	1

Recommended CALPUFF Parameters chosen by EPA Region 10 states for use in BART modeling.						
Input Group	**Group Description**	**Sequence**	**Variable**	**Description**	**Default Value[a]**	**Recommended Value**
5		19	NN2	(Met. Period to end output)	(10)	10
7	Dry Dep Chem		Dry Gas Dep	Chemical parameters of gaseous deposition species	User Defined	defaults
8	Dry Dep Size		Dry Part. Dep	Chemical parameters of particulate deposition species	User Defined	defaults
9	Dry Dep Misc	1	RCUTR	Reference cuticle resistance (s/cm)	30	30
9		2	RGR	Reference ground resistance (s/cm)	10	10
9		3	REACTR	Reference reactivity	8	8
9		4	NINT	Number of particle-size intervals	9	9
9		5	IVEG	Vegetative state (1 = active and unstressed; 2=active and stressed)	1	1
10	Wet Dep		Wet Dep	Wet deposition parameters	User Defined	defaults
11	Chemistry	1	MOZ	Ozone background? (0 = constant background value; 1 = read from ozone.dat)	0	0
11		2	BCKO3	Ozone default (ppb) (Use only for missing data)	80	60
11		3	BCKNH3	Ammonia background (ppb)	10	17
11		4	RNITE1	Nighttime SO2 loss rate (%/hr)	0.2	0.2
11		5	RNITE2	Nighttime NOx loss rate (%/hr)	2	2
11		6	RNITE3	Nighttime HNO3 loss rate (%/hr)	2	2
11		7	MH2O2	H2O2 data input option	1	1
11		8	BCKH2O2	Monthly H2O2 concentrations	1	12*1
			BKPMF	Fine particulate concentration	12 * 1.00	not used
			OFRAC	Organic fraction of Fine Particulate	2*0.15, 9*0.20, 1*0.15	not used
			VCNX	VOC / NOX ratio	12 * 50.00	not used
12	Dispersion	1	SYTDEP	Horizontal size (m) to switch to time dependence	550	550
12		2	MHFTSZ	Use Heffter for vertical dispersion? (0 = No)	0	0
12		3	JSUP	PG Stability class above mixed layer	5	5
12		4	CONK1	Stable dispersion constant (Eq 2.7-3)	0.01	0.01
12		5	CONK2	Neutral dispersion constant (Eq 2.7-4)	0.1	0.1
12		6	TBD	Transition for downwash algorithms (0.5 = ISC)	0.5	0.5
12		7	IURB1	Beginning urban landuse type	10	10
12		8	IURB2	Ending urban landuse type	19	19
12		9	ILANDUIN	Land use type (20 = Unirrigated agricultural land)	20	20
12		10	ZOIN	Roughness length (m)	0.25	0.25
12		11	XLAIIN	Leaf area index	3.0	3.0
12		12	ELEVIN	Met. Station elevation (m above MSL)	0.0	0.0
12		13	XLATIN	Met. Station North latitude (degrees)	-999.0	-999.0
12		14	XLONIN	Met. Station West longitude (degrees)	-999.0	-999.0
12		15	ANEMHT	Anemometer height of ISC meteorological data (m)	10.0	10.0
12		16	ISIGMAV	Lateral turbulence (Not used with ISC meteorology)	1	1
12		17	IMIXCTDM	Mixing heights (Not used with ISC meteorology)	0	0
12		18	XMXLEN	Maximum slug length in units of DGRIDKM	1.0	1
12		19	XSAMLEN	Maximum puff travel distance per sampling step (units of DGRIDKM)	1.0	1
12		20	MXNEW	Maximum number of puffs per hour	99	99
12		21	MXSAM	Maximum sampling steps per hour	99	99
12		22	NCOUNT	Iterations when computing Transport Wind (Calmet & Profile Winds)	2	2
12		23	SYMIN	Minimum lateral dispersion of new puff (m)	1.0	1
12		24	SZMIN	Minimum vertical dispersion of new puff (m)	1.0	1
12		25	SVMIN	Array of minimum lateral turbulence (m/s)	6 * 0.50	6 * 0.50
12		26	SWMIN	Array of minimum vertical turbulence (m/s)	0.20,0.12,0.08, 0.06,0.03,0.01 6	

Recommended CALPUFF Parameters chosen by EPA Region 10 states for use in BART modeling.						
Input Group	**Group Description**	**Sequence**	**Variable**	**Description**	**Default Value[a]**	**Recommended Value**
12		27	CDIV (1), (2)	Divergence criterion for dw/dz (1/s)	0.01 (0.0,0.0)	0.0,0.0
12		28	WSCALM	Minimum non-calm wind speed (m/s)	0.5	0.5
12		29	XMAXZI	Maximum mixing height (m)	3000	3000
12		30	XMINZI	Minimum mixing height (m)	50	50
12		31	WSCAT	Upper bounds 1st 5 wind speed classes (m/s)	1.54,3.09,5.14, 8. 23,10.8	1.54,3.09,5.14,8. 23,10.8
12		32	PLX0	Wind speed power-law exponents	0.07,0.07,0.10, 0.15,0.35,0.55	0.07,0.07,0.10,0. 15,0.35,0.55
12		33	PTGO	Potential temperature gradients PG E and F (deg/km)	0.020,0.035	0.020,0.035
12		34	PPC	Plume path coefficients (only if MCTADJ = 3)	0.5,0.5,0.5,0.5, 0.35,0.35	0.5,0.5,0.5,0.5,0. 35,0.35
12		35	SL2PF	Maximum Sy/puff length	10.0	10.0
12		36	NSPLIT	Number of puffs when puffs split	3	3
12		37	IRESPLIT	Hours when puff are eligible to split	User Defined	
12		38	ZISPLIT	Previous hour's mixing height(minimum)(m)	100.0	100.0
12		39	ROLDMAX	Previous Max mix ht/current mix ht ratio must be less then this value for puff to split	0.25	0.25
12		40	NSPLITH	Number of puffs when puffs split horizontally	5	5
12		41	SYSPLITH	Min sigma-y (grid cell units) of puff before horiz split	1.0	1.0
12	12	42	SHSPLITH	Min puff elongation rate per hr from wind shear before horiz split	2.0	2.0
12		43	CNSPLITH	Min conc g/m3 before puff may split horizontally	1.0E-07	1.0E-07
12		44	EPSSLUG	Convergence criterion for slug sampling integration	1.00E-04	1.00E-04
12		45	EPSAREA	Convergence criterion for area source integration	1.00E-06	1.00E-06
12		46	DSRISE	Step length for rise integration	1.0	1.0
12		47	HTMINBC		500.0	500.0
12		48	RSAMPBC		10.0	10.0
12		49	MDEPBC		1	1
13	Point Source	1	NPT1	Number of point sources	User Defined	
13		2	IPTU	Units of emission rates (1 = g/s)	1	
13		3	NSPT1	Number of point source-species combinations	0	
13		4	NPT2	Number of point sources with fully variable emission rates	0	
13			Point Sources	Point sources characteristics	User Defined	
14	Area Source		Area Sources	Area sources characteristics	User Defined	
15	Volume Source		Volume	Volume sources characteristics	User Defined Sources	
16	Line Source		Line Sources	Buoyant lines source characteristics	User Defined	
17	Receptors		NREC	Number of user defined receptors	User Defined	
17			Receptor Data	Location and elevation (MSL) of receptors	User Defined	

Appendix E

CALPOST Parameter Values

Appendix E
CALPOST Parameter Values

Table F-1. Recommended CALPOST parameter values chosen by the Region 10 states for use in BART modeling

Input Group	Variable	Description	Default Value	Recommended Value
1	ASPEC	Species to process	VISIB	VISIB
1	ILAYER	Layer/deposition code (1 = CALPUFF concentrations; -3 = wet+dry deposition fluxes)	1	1
1	LBACK	Add Hourly Background Concentrations/Fluxes?	F	F
1	MFRH	Particle growth curve for hygroscopic species	2	2
2	RHMAX	Maximum relative humidity (%) used in particle growth curve	98	95
2	LDRING	Report results by Discrete receptor Ring, if Discrete Receptors used. (T = true)	T	
		Modeled species to be included in computing the light extinction		
2	LVSO4	Include SO4?	T	T
2	LVNO3	Include NO3?	T	T
2	LVOC	Include Organic Carbon?	T	T
2	LVPMC	Include Coarse Particles?	T	T
2	LVPMF	Include Fine Particles?	T	T
2	LVEC	Include Elemental Carbon?	T	T
2	LVBK	when ranking for TOP-N, TOP-50, and Exceedance tables Include BACKGROUND?	T	T
2	SPECPMC	Species name used for particulates in MODEL.DAT file: COARSE =	PMC	PMC
2	SPECPMF	Species name used for particulates in MODEL.DAT file: FINE =	PMF	PMF
		Extinction Efficiencies (1/Mm per ug/m**3)		
2	EEPMC	PM COARSE =	0.6	0.6
2	EEPMF	PM FINE =	1.0	1.0
2	EEPMCBK	Background PM COARSE	0.6	0.6
2	EESO4	SO4 =	3.0	3.0
2	EENO3	NO3 =	3.0	3.0
2	EEOC	Organic Carbon =	4.0	4.0
2	EESOIL	Soil =	1.0	1.0
2	EEEC	Elemental Carbon =	10.0	10.0
2	LAVER	Method used for 24-hr avg % change light extinction	F	F
2	MVISBK	Method used for background light extinction (2 = Hourly RH adjustment; 6 = FLAG seasonal f(RH))	2 or 6	6
2	RHFAC	Monthly RH adjustment factors from FLAG (unique for each Class I area)	Yes if 6	EPA
		Background monthly extinction coefficients (FLAG) unique for each Class I area		
2	BKSO4	Assume all hygroscopic species as SO4 (raw extinction value without scattering efficiency adjustment)		*see table*
2	BKNO3			*see table*
2	BKPMC			*see table*
2	BKOC			*see table*
2	BKSOIL	Assume all non-hygroscopic species as Soil		*see table*
2	BKEC			*see table*
2	BEXTRAY	Extinction due to Rayleigh scattering	10.0	10.0
		Averaging time(s) reported		
3	L1PD	Averaging period of model output	F	F
3	L1HR	1-hr averages	F	F
3	L3HR	3-hr averages	F	F
3	L24HR	24-hr averages	T	T
3	LRUNL	Run lengtyh (annual)	F	F
3	LT50	Top 50 table for each averaging time selected	T	F
3	LTOPN			1
3	NTOP			1
3	ITOP			

Report

Protocol for the Application of CALPUFF Determination Modeling Pursuant to BART Regulation—PGE Boardman Plant (Revised)

Prepared for

Portland General Electric

January 2007

Prepared by

CH2MHILL

Contents

SECTION 1

Introduction and Protocol Objectives

1.1 Background

The U.S. Environmental Protection Agency (EPA) issued the final *Guidelines for Best Available Retrofit Technology* (BART) Determinations (BART Guideline) as required under the Regional Haze rule on July 6, 2006. The BART Guideline was designed to help states do the following: (1) identify those sources that must comply with the BART requirement and (2) determine the level of control technology that represents BART for each source. The Portland General Electric (PGE) coal-fired power plant located in Boardman, Oregon (the Boardman plant) is a BART-eligible source for which a BART emission limit evaluation is required. The BART Guideline requires a modeling analysis for these types of sources. This document presents the protocol for the determination modeling analysis.

1.2 Objectives

The protocol presented here is based on the combined agency protocol developed by the Idaho Department of Environmental Quality (IDEQ), the Oregon Department of Environmental Quality (ODEQ), and the Washington Department of Ecology (WDOE) (ODEQ, 2006). The objectives of this protocol are as follows:

- Describe determination modeling approach
- Present determination modeling methodology
- Define emissions and stack parameters for all control options to be modeled
- Define presentation of results

SECTION 2

Modeling Approach

The modeling analysis will be used to evaluate the visibility improvements of various BART control options on Class I areas in Oregon and Washington that could be affected by the Boardman plant. These areas are presented in Appendix A. Although not a Class I area, the Columbia River Gorge Scenic Area will also be evaluated in the BART determination modeling, for informational purposes only.

Both pre-BART control and post-BART control scenarios will be analyzed to compare visibility. Maximum 24-hour past actual emissions will be compared with future 24-hour maximum emissions and analyzed on a pollutant-by-pollutant basis. Frequency, magnitude, and duration of impairment will be evaluated in the determination analysis.

Sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and direct particulate matter (PM) emissions, including both PM_{10} and $PM_{2.5}$, will be included in the determination modeling analysis, as required in the BART Guideline. Volatile organic compound (VOC) and ammonia emissions will not be included in the analysis.

Consistent with the intent of the BART Guideline, the natural visibility background is defined as the 20 percent best days. The natural background values for Class I areas will be consistent with those provided in the combined agency protocol (ODEQ, 2006). Background values for both the Class I areas and the Columbia River Gorge Scenic Area are presented in Appendix B.

SECTION 3

Modeling Methodology

As required by the combined agency protocol (ODEQ, 2006) and supported by the Interagency Workgroup on Air Quality Modeling (EPA, 1998) and the Federal Land Managers' Air Quality Related Values Workgroup (FLAG, 2000), the CALPUFF suite of programs will be used for the BART determination modeling. The CALPUFF modules and their version numbers that will be used in the determination modeling are presented in Table 3-1. Modeling parameters for each module are described in this section and are presented in the appendixes.

TABLE 3-1
CALPUFF Modeling System

Program	Version	Level
CALMET	6.211	060414
CALPUFF	6.112	060412
CALPOST	6.131	060410
POSTUTIL	1.52	060412

3.1 CALMET

Details of the parameter settings in CALMET are provided in Appendix C; however, the major assumptions are summarized below. These data were provided by ODEQ.

1. The initial-guess fields used the 12-kilometer (km) MM5 outputs, forecast hours 13 – 24 from every 00Z and 12Z initialization, taken from University of Washington (UW) archives, for the 3 years from January 2003 through December 2005.
2. BART determination modeling will utilize the wind fields at 4-km resolution.
3. There are 10 vertical layers with face heights of 0, 20, 40, 65, 120, 200, 400, 700, 1200, 2200, and 4000 meters.
4. CALMET was run using NOOBS = 1. Upper air, precipitation, and relative humidity data were taken from MM5.
5. The surface wind observations were ignored by setting the relative weight of surface winds to essentially zero (R1 = 1.0E-06). Cloud cover data were the only surface observation data that were effectively used in CALMET.
6. Precipitation data were obtained from MM5, so MM5NPSTA = -1.
7. No weighting of surface and upper air observations, and BIAS = 0, and ICALM = 0.
8. The terrain scale factor TERRAD = 12.

9. Land use and terrain data were developed using the North American 30-arc-second data.

10. The dispersion modeling will use CALMET wind fields for the 3-year period 2003–2005. These data were developed for the three states using CALMET Version 6.211 and were provided by ODEQ. This domain is shown in Figure 3-1.

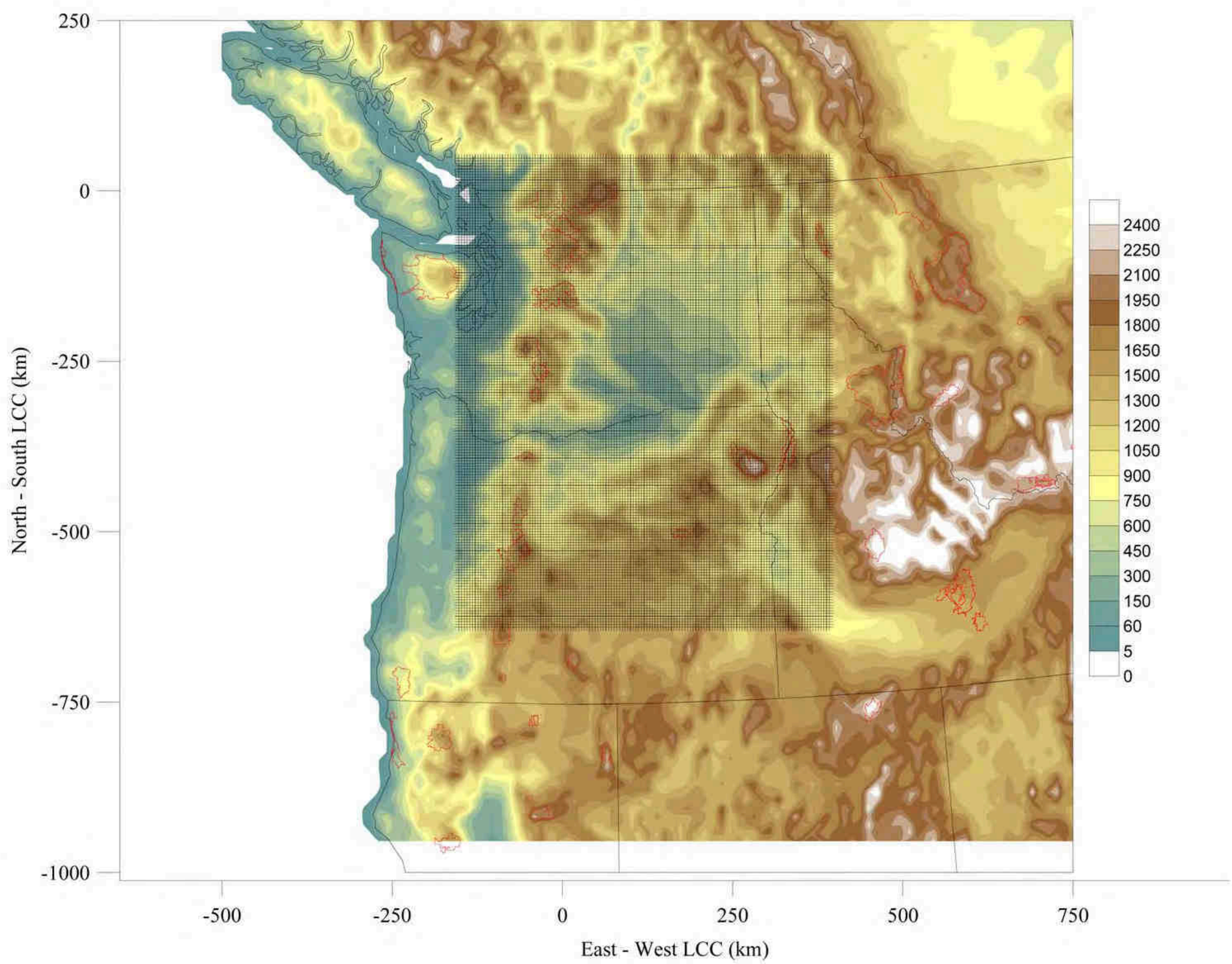

Figure 3-1 CALMET Meteorological Domain.

3.2 CALPUFF

Details of the parameter settings in CALPUFF are provided in Appendix D; however, the major features are summarized below.

1. The BART determination modeling will examine the visibility impairment on Class I areas within 300 km of the Boardman plant. The computational modeling domain will include all Class I areas within a 300-km radius of PGE Boardman.

2. Pasquill-Gifford Dispersion coefficients will be used.
3. MESOPUFF-II chemistry algorithm will be used.
4. Building downwash will be ignored.
5. Puff splitting will not be used, following the recommendations of the Federal Land Managers (FLMs).
6. Source elevations that will be entered in CALPUFF will not use actual elevations but will be based on the modeled terrain surface used in CALMET for developing wind fields. The same algorithm in CALMET that determines the elevations of the observational stations will be used to make this calculation. The modified source elevation was set at 225 meters, as determined by CH2M HILL.

3.2.1 Species

Primary emission species analyzed will include the input species PM, SO_2, sulfates (SO_4), and NO_x; and the additional modeled species nitric acid (HNO_3) and nitrates (NO_3). Sulfur dioxide emissions will be reviewed to ensure that "double-counting" is avoided.

Both filterable and condensable fractions of PM will be included in the analysis. The condensable fraction will be treated as primary emissions in the CALPUFF input file and assumed to be 100 percent in the $PM_{2.5}$ fraction. The primary PM species will be treated as follows:

Filterable:
- Elemental Carbon (EC) (< 2.5 microns [µm])
- PM Fine (PMF) (< 2.5 µm)
- PM Coarse (PMC) (2.5 – 10 µm)

Condensable:
- Organic Carbon (OC) (secondary organic aerosol [SOA])
- Inorganic Aerosol (SO_4)
- Non-SO_4 inorganic aerosol

The primary emission species sizing are presented as follows:

Pollutant	Mean Diameter	Standard Deviation
SO_4, NO_3, PMF, SOA, EC	0.50 microns	1.5
PMC	5.00 microns	1.5

3.2.2 Background Values

A single ozone background value of 60 parts per billion (ppb) will be used for all months for all Class I areas.

As with the ozone background, a single value of 17 ppb will be used for the ammonia background. This value is supported by measurements made in 1996–1997 at Abbotsford in the Fraser River Valley of British Columbia.

3.2.3 Receptor Locations

Visibility impacts will be computed at all Class I areas and the Columbia River Gorge Scenic Area if they lie within a 300-km radius of the Boardman plant. The geolocations of the receptor points and their elevations for the Class I areas that will be used in the modeling are consistent with the ODEQ exemption modeling and were downloaded from the National Park Service Web site at http://www2.nature.nps.gov/air/Maps/Receptors/index.cfm>.

Receptor points and elevations for the Columbia River Gorge Scenic Area were provided by ODEQ.

3.3 CALPOST and Visibility Post-Processing

Details of the parameter setting in CALPOST are provided in Appendix E. The following assumptions will be used in CALPOST and POSTUTIL to calculate the visibility impairment:

1. For the visibility calculation, Method 6 will be employed. This method uses monthly average relative humidity and f(RH) values for each Class I area as provided in Appendix B, which are based on the EPA Guidance for Regional Haze analysis (EPA, 2003).

2. Particulate species for the visibility analysis will include SO_4, NO_3, EC, OC, PMF, and PMC, as reported in the CALPOST output files.

3. POSTUTIL will not be used to speciate modeled PM_{10} concentrations, as PM_{10} will be speciated into its components (PMF, PMC, SOA, EC, SO_4) and entered as primary emissions in CALPUFF. In addition, HNO_3/NO_3 partition option in POSTUTIL will not be used for ammonia limiting.

4. Natural background extinction calculations will use the 20 percent best days for each Class I area. The natural background for the 20 percent best days has been refined from that which is in "*Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*" (EPA, 2003). The extinction coefficients for the 20 percent best days have been calculated following the approach taken in the Draft Montana BART modeling protocol. This procedure uses the haze index (HI) in deciviews at the 10th percentile (median of the 20 percent best days) and an activity factor that is calculated for each Class I area. Table B-1, providing the monthly f(RH) and 20 percent best days coefficients, is provided in Appendix B and is based on data from EPA (2003). For the exemption modeling, the Rayleigh scattering value will be 10 Mm-1 for all Class I areas.

   The 98th percentile value will be calculated for all BART-eligible sources at each mandatory Class I area.

5. The CALPOST "LST" output files will be used to determine the 98th percentile of visibility impairment for each receptor in CLASS I areas.

6. The contribution threshold has the implied level of precision equal to the level of precision reported by CALPOST. Therefore, the 98th percentile value will be reported to three decimal places.

3.4 Visibility Calculation

The CALPUFF modeling techniques presented in this section will provide ground-level concentrations of visibility-impairing pollutants. The concentration estimates from CALPUFF are used with the current FLAG equation to calculate the extinction coefficient, as shown below:

$$b_{ext} = 3\ f(RH)\ [(NH_4)_2SO_4] + 3\ f(RH)\ [NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray}$$

As described in the IWAQM Phase 2 Report (EPA, 1998), the change in visibility for the BART exemption analysis is compared against background conditions. The delta-deciview, Δdv, value is calculated from the source's contribution to extinction, $b_{ext\ (source)}$, and background extinction, $b_{ext(bkg)}$, as follows:

$$\Delta dv = 10\ ln\ [\ (\ b_{ext(bkg)} + b_{ext\ (source)}\ )\ /\ (\ b_{ext(bkg)}\ )\ ]$$

SECTION 4

Emissions and Stack Data

Emissions to be modeled for determination modeling will not include startup, shutdown, or malfunction emissions. The emissions and stack data used for the determination modeling are summarized in Appendix F. Emissions were derived by Black & Veatch for PGE as summarized in a memorandum presented in Appendix G.

The control scenarios being modeled for the determination modeling are listed below:

1. NO_x Controlled Outlet Conditions
   a. Selective Catalytic Reduction
   b. New Low-NO_x Burners with Modified Over-Fire Air (OFA) System
2. SO_2 Controlled Outlet Conditions
   a. Wet Flue Gas Desulfurization
   b. Semi-Dry Flue Gas Desulfurization

Existing emissions of PM are already controlled by an electrostatic precipitator. As a result, emissions of SO_2 and NO_x are each more than 10 times the emissions of particulate. The exemption modeling conducted by ODEQ shows the contribution of PM to the highest visibility impairment days to be less than 2 percent. Consequently, PM controls will not be included in the determination analysis.

Consistent with the BART guidelines, the required maximum 24-hour emission rates used in the modeling will be based on a 30-day rolling average permit limit. Each of the above control options will be analyzed for each pollutant to determine the most effective control by pollutant. Following that analysis, the model will be run combining the most effective controls by pollutants to determine the maximum improvement in visibility.

SECTION 5

Presentation of Results

The improvement in visibility for BART determination is based on the change in HI from pre-BART control to post-BART control for PGE relative to natural background for each Class I area. Comparison tables for pre-BART control and post-BART control visibility impacts will be documented for use in the BART control evaluation. Frequency, magnitude, and duration of any visibility impairment will be included in the documentation.

SECTION 6

References

Federal Land Managers' Air Quality Related Values Workgroup (FLAG). 2000. *Phase I Report*. December 2000.

Oregon Department of Environmental Quality (ODEQ). 2006. *Modeling Protocol for Washington, Oregon, and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation.* October 11, 2006.

U.S. Environmental Protection Agency (EPA). 1998. *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*. EPA-454/R-98-019. December 1998.

U.S. Environmental Protection Agency (EPA). 2003. *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule*. EPA-454/B-03-005. September 2003.

U.S. Environmental Protection Agency (EPA). 2005. *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations*. Federal Register, Vol. 70, No. 128. Pp. 39104–30172. July 6, 2005.

APPENDIX A
Class I Federal Areas

Table A-1. Federal Mandatory Class I Areas Evaluated in PGE Boardman Analysis.

Class I Area	Federal Land Manager
Oregon	
Diamond Peak Wilderness	Forest Service
Eagle Cap Wilderness	Forest Service
Hells Canyon Wilderness	Forest Service
Three Sisters Wilderness	Forest Service
Mount Hood Wilderness	Forest Service
Mount Jefferson Wilderness	Forest Service
Mount Washington Wilderness	Forest Service
Strawberry Mountain Wilderness	Forest Service
Washington	
Alpine Lakes Wilderness	Forest Service
Goat Rocks Wilderness	Forest Service
Glacier Peak Wilderness	Forest Service
Mount Adams Wilderness	Forest Service
Mount Rainier National Park	Park Service
North Cascades National Park	Park Service

APPENDIX B

Natural Visibility Background and Monthly Relative Humidity f(RH)

Table B-1 Adjustment to speciated particulate (Western States) to reflect 20% Best Visibility Days conditions
Monthly f(RH) are from *Appendix A of Draft Guidance for Estimating Natural Visibility Conditions under the RHR (Sept. 2003)*.
Background extinction coefficients (20% Best Days) have been calculated using Annual Avg bext, Best 20% bext, and activity factors.

		CALPOST Input Group 2 Monthly extinction coefficients for hygroscopic species (RHFAC)												CALPOST Input Group 2 Background extinction coefficients (20% Best Days)					
		Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	BKSO4	BKNO3	BKPMC	BKOC	SOIL	BKEC
Class I Area	State	f(RH)	f(RH)	f(RH)	f(RH)	f(RH)	f(RH)	f(RH)	f(RH)	f(RH)	f(RH)	f(RH)	f(RH)	ug/m3	ug/m3	ug/m3	ug/m3	ug/m3	ug/m3
Hells Canyon	ID	3.70	3.12	2.51	2.17	2.12	2.00	1.63	1.58	1.79	2.41	3.45	3.87	0.048	0.040	1.21	0.190	0.202	0.008
Diamond Peak	OR	4.52	3.96	3.64	3.66	3.16	3.12	2.90	2.93	3.05	3.67	4.55	4.57	0.053	0.044	1.33	0.208	0.222	0.009
Eagle Cap	OR	3.77	3.16	2.47	2.10	2.04	1.87	1.61	1.56	1.61	2.25	3.44	3.97	0.049	0.041	1.22	0.191	0.203	0.008
Mount Hood	OR	4.29	3.81	3.46	3.87	2.95	3.15	2.85	3.00	3.10	3.86	4.53	4.55	0.053	0.044	1.33	0.209	0.222	0.009
Mount Jefferson	OR	4.41	3.90	3.56	3.74	3.07	3.11	2.89	2.91	3.03	3.78	4.55	4.54	0.054	0.045	1.34	0.210	0.223	0.009
Mount Washington	OR	4.44	3.93	3.58	3.73	3.09	3.11	2.98	2.91	3.02	3.76	4.56	4.56	0.054	0.045	1.36	0.213	0.227	0.009
Strawberry Mountain	OR	3.89	3.33	2.75	2.93	2.27	2.39	1.98	1.97	1.87	2.63	3.69	4.07	0.050	0.042	1.26	0.197	0.210	0.008
Three Sisters	OR	4.47	3.95	3.61	3.72	3.11	3.11	3.00	2.91	3.03	3.79	4.60	4.57	0.054	0.045	1.35	0.212	0.226	0.009
Alpine Lakes	WA	4.25	3.79	3.47	3.90	2.93	3.22	2.92	3.12	3.25	3.91	4.47	4.51	0.054	0.045	1.35	0.212	0.225	0.009
Glacier Peak	WA	4.16	3.72	3.42	3.75	2.91	3.16	2.88	3.14	3.33	3.90	4.42	4.43	0.054	0.045	1.34	0.210	0.223	0.009
Goat Rocks	WA	4.25	3.75	3.36	4.24	2.83	3.38	3.03	3.19	3.07	3.77	4.42	4.55	0.054	0.045	1.34	0.210	0.224	0.009
Mount Adams	WA	4.29	3.80	3.44	4.40	2.92	3.49	3.12	3.27	3.13	3.86	4.49	4.56	0.053	0.044	1.33	0.209	0.222	0.009
Mount Rainier	WA	4.42	3.96	3.64	4.65	3.06	3.69	3.30	3.50	3.40	4.11	4.66	4.66	0.055	0.045	1.36	0.214	0.227	0.009
North Cascades NP	WA	4.10	3.69	3.43	3.74	2.93	3.20	2.93	3.23	3.45	3.93	4.39	4.38	0.053	0.044	1.33	0.209	0.222	0.009
Columbia River Gorge	OR-WA	5.03	5.03	2.59	2.59	2.59	2.11	2.11	2.11	3.51	3.51	3.51	5.03	0.569	0.231	4.85	1.05	0.217	0.205

APPENDIX C
CALMET Parameter Values

Appendix C
CALMET Parameter Values

Table C-1 Recommended CALMET parameters chosen by the Region 10 states for use in BART modeling

Input Group	Variable	Description	Default Value	Recommended Value
0	DIADAT	Input file: preprocessed surface temperature data (DIAG.DAT)	User Defined	
0	GEODAT	Input file: Geophysical data (GEO.DAT)	User Defined	User Define
0	LCFILES	Convert file name to lower case	User Defined	
0	METDAT	Output file (CALMET.DAT)	User Defined	
0	METLST	Output file (CALMET.LST)	User Defined	
0	MM4DAT	Input file: MM4 data (MM4.DAT)	User Defined	
0	NOWSTA	Input files: Names of NOWSTA overwater stations	User Defined	0
0	NUSTA	Number of upper air data sites	User Defined	0
0	PACDAT	Output file: in Mesopuff II format (PACOUT.DAT)	User Defined	
0	PRCDAT	Input file: Precipitation data (PRECIP.DAT)	User Defined	
0	PRGDAT	Input file: CSUMM prognostic wind data (PROG.DAT)	User Defined	
0	SEADAT	Input files: Names of NOWSTA overwater stations (SEAn.DAT)	User Defined	
0	SRFDAT	Input file: Surface data (SURF.DAT)	User Defined	
0	TSTFRD	Output file (TEST.FRD)	User Defined	
0	TSTKIN	Output file (TEST.KIN)	User Defined	
0	TSTOUT	Output file (TEST.OUT)	User Defined	
0	TSTPRT	Output file (TEST.PRT)	User Defined	
0	TSTSLP	Output file (TEST.SLP)	User Defined	
0	UPDAT	Input files: Names of NUSTA upper air data files (UPn.DAT)	UPn.DAT	
0	WTDAT	Input file: Terrain weighting factors (WT.DAT)	User Defined	
1	CLDDAT	Input file: Cloud data (CLOUD.DAT)	User Defined	Not used
1	IBDY	Beginning day	User Defined	
1	IBHR	Beginning hour	User Defined	
1	IBMO	Beginning month	User Defined	
1	IBTZ	Base time zone	User Defined	8
1	IBYR	Beginning year	User Defined	
1	IRLG	Number of hours to simulate	User Defined	User Define
1	IRTYPE	Output file type to create (must be 1 for CALPUFF)	1	1
1	ITEST	Flag to stop run after Setup Phase	2	2
1	LCALGRD	Are w-components and temperature needed?	T	T
2	DATUM	WGS-G, NWS-27, NWS-84, ESR-S,…		NWS84
2	DGRIDKM	Grid spacing	User Defined	4
2	IUTMZN	UTM Zone	User Defined	User Define
2	LLCONF	When using Lambert Conformal map coordinates - rotate winds from true north to map north?	F	F
2	NX	Number of east-west grid cells	User Defined	373
2	NY	Number of north-south grid cells	User Defined	316
2	NZ	Number of vertical layers	User Defined	10
2	RLAT0	Latitude used if LLCONF = T	User Defined	49.0N
2	RLON0	Longitude used if LLCONF = T	User Defined	121.0W
2	XLAT0	Southwest grid cell latitude	User Defined	User Define
2	XLAT1	Latitude of 1st standard parallel	User Defined	30
2	XLAT2	Latitude of 2nd standard parallel	User Defined	60
2	XORIGKM	Southwest grid cell X coordinate	User Defined	-572
2	YLON0	Southwest grid cell longitude	User Defined	-956
2	YORIGKM	Southwest grid cell Y coordinate	User Defined	User Define
2	ZFACE	Vertical cell face heights (NZ+1 values)	User Defined	0,20,40,65,120,200, 400, 700,1200,2200,4000
3	IFORMO	Format of unformatted file (1 for CALPUFF)	1	1
3	LSAVE	Save met. data fields in an unformatted file?	T	T

Table C-1 Recommended CALMET parameters chosen by the Region 10 states for use in BART modeling

Input Group	Variable	Description	Default Value	Recommended Value
4	ICLOUD	Is cloud data to be input as gridded fields? (0 = No)	0	0
4	IFORMC	Format of cloud data (2 = formatted)	2	2
4	IFORMP	Format of precipitation data (2 = formatted)	2	2
4	IFORMS	Format of surface data (2 = formatted)	2	2
4	NOOBS	Use or non-use of surface, overwater, upper observations		1
4	NPSTA	Number of stations in PRECIP.DAT	User Defined	-1
4	NSSTA	Number of stations in SURF.DAT file	User Defined	115
5	ALPHA	Empirical factor triggering kinematic effects	0.1	0.1
5	BIAS	Surface/upper-air weighting factors (NZ values)	NZ*0	NZ*0
5	CRITFN	Critical Froude number	1	1
5	DIVLIM	Maximum acceptable divergence	5.00E-06	5.00E-06
5	FEXTR2	Multiplicative scaling factor for extrap surface obs to uppr layrs	NZ*0.0	
5	ICALM	Extrapolate surface calms to upper layers? (0 = No)	0	0
5	IDIOPT1	Compute temperatures from observations (0 = True)	0	0
5	IDIOPT2	Compute domain-average lapse rates? (0 = True)	0	0
5	IDIOPT3	Compute internally initial guess winds? (0 = True)	0	0
5	IDIOPT4	Read surface winds from SURF.DAT? (0 = True)	0	0
5	IDIOPT5	Read aloft winds from UPn.DAT? (0 = True)	0	0
5	IEXTRP	Extrapolate surface winds to upper layers? (-4 = use similarity theory and ignore layer 1 of upper air station data)	-4	-1
5	IFRADJ	Adjust winds using Froude number effects? (1 = Yes)	1	1
5	IKINE	Adjust winds using kinematic effects? (1 = Yes)	0	0
5	IOBR	Use O'Brien procedure for vertical winds? (0 = No)	0	0
5	IPROG	Using prognostic or MM-FDDA data? (0 = No)	0	14
5	ISLOPE	Compute slope flows? (1 = Yes)	1	1
5	ISTEPPG	Timestep (hours) of the prognostic model input data	1	1
5	ISURFT	Surface station to use for surface temperature (between 1 and NSSTA)	User Defined	98
5	IUPT	Station for lapse rates (between 1 and NUSTA)	User Defined	1
5	IUPWND	Upper air station for domain winds (-1 = 1/r**2 interpolation of all stations)	-1	-1
5	IWFCOD	Generate winds by diagnostic wind module? (1 = Yes)	1	1
5	KBAR	Level (1 to NZ) up to which barriers apply	NZ	10
5	LLBREZE	Use Lake Breeze module	F	F
5	LVARY	Use varying radius to develop surface winds?	F	F
5	METBXID	Station IDs in the region	User Defined	
5	NBAR	Number of Barriers to interpolation	User Defined	0
5	NBOX	Number of Lake Breeze regions	User Defined	0
5	NINTR2	Max number of stations for interpolations (NA values)	99	99
5	NITER	Max number of passes in divergence minimization	50	50
5	NLB	Number of stations in region	User Defined	0
5	NSMTH	Number of passes in smoothing (NZ values)	2, 4*(NZ-1)	1,2,2,3,3,4,4,4,4,4
5	R1	Relative weight at surface of Step 1 field and obs	User Defined	1.00E-06
5	R2	Relative weight aloft of Step 1 field and obs	User Defined	1.00E-06
5	RMAX1	Max surface over-land extrapolation radius (km)	User Defined	200
5	RMAX2	Max aloft over-land extrapolation radius (km)	User Defined	200
5	RMAX3	Maximum over-water extrapolation radius (km)	User Defined	200
5	RMIN	Minimum extrapolation radius (km)	0.1	0.1
5	RMIN2	Distance (km) around an upper air site where vertical extrapolation is excluded (Set to -1 if IEXTRP = ±4)	4	-1
5	RPROG	Weighting factor for CSUMM prognostic wind data	User Defined	0
5	TERRAD	Radius of influence of terrain features (km)	User Defined	12
5	XBBAR	X coordinate of Beginning of each barrier	User Defined	0

Table C-1 Recommended CALMET parameters chosen by the Region 10 states for use in BART modeling				
Input Group	**Variable**	**Description**	**Default Value**	**Recommended Value**
5	XBCST	X Point defining the coastline (straight line)	User Defined	0
5	XEBAR	X coordinate of Ending of each barrier	User Defined	0
5	XECST	X Point	User Defined	0
5	XG1	X Grid line 1 defining region of interest	User Defined	0
5	XG2	X Grid line 2	User Defined	0
5	YBBAR	Y coordinate of Beginning of each barrier	User Defined	0
5	YBCST	Y Point	User Defined	0
5	YEBAR	Y coordinate of Ending of each barrier	User Defined	0
5	YECST	Y Point	User Defined	0
5	YG1	Y Grid line 1	User Defined	0
5	YG2	Y Grid Line 2	User Defined	0
5	ZUPT	Depth of domain-average lapse rate (m)	200	200
5	ZUPWND	Bottom and top of layer for 1st guess winds (m)	1, 1000	1.,1000.
6	CONSTB	Neutral mixing height B constant	1.41	1.41
6	CONSTE	Convective mixing height E constant	0.15	0.15
6	CONSTN	Stable mixing height N constant	2400	2400
6	CONSTW	Over-water mixing height W constant	0.16	0.16
6	CUTP	Minimum cut off precip rate (mm/hr)	0.01	0.01
6	DPTMIN	Minimum capping potential temperature lapse rate	0.001	0.001
6	DSHELF	Coastal/shallow water length scale	0	0
6	DZZI	Depth for computing capping lapse rate (m)	200	200
6	FCORIOL	Absolute value of Coriolis parameter	1.00E-04	1.00E-04
6	HAFANG	Half-angle for looking upwind (degrees)	30	30
6	IAVET	Conduct spatial averaging of temperature? (1 = True)	1	1
6	IAVEZI	Spatial averaging of mixing heights? (1 = True)	1	1
6	ICOARE	Overwater surface fluxes method and parameters	10	10
6	ICOOL	COARE cool skin layer computation	0	0
6	ILEVZI	Layer to use in upwind averaging (between 1 and NZ)	1	1
6	ILUOC3D	Land use category ocean in 3D.DAT datasets	16	16
6	IMIXH	Method to compute the convective mixing height	1	1
6	IRAD	Form of temperature interpolation (1 = 1/r)	1	1
6	IRHPROG	3D relative humidity from observations or from prognostic data	0	1
6	ITPROG	3D temps from obs or from prognostic data?	0	2
6	ITWPROG	Option for overwater lapse rates used in convective mixing height growth	0	2
6	IWARM	COARE warm layer computation	0	0
6	JWAT1	Beginning landuse type defining water	999	55
6	JWAT2	Ending landuse type defining water	999	55
6	MNMDAV	Max averaging radius (number of grid cells)	1	1
6	NFLAGP	Method for precipitation interpolation (2 = 1/r**2)	2	2
6	NUMTS	Max number of stations in temperature interpolations	5	10
6	SIGMAP	Precip radius for interpolations (km)	100	12
6	TGDEFA	Default over-water capping lapse rate (K/m)	-0.0045	-0.0045
6	TGDEFB	Default over-water mixed layer lapse rate (K/m)	-0.0098	-0.0098
6	THRESHL	Threshold buoyancy flux required to sustain convective mixing height growth overland	0.05	0.05
6	THRESHW	Threshold buoyancy flux required to sustain convective mixing height growth overwater	0.05	0.05
6	TRADKM	Radius of temperature interpolation (km)	500	500
6	ZIMAX	Maximum over-land mixing height (m)	3000	3000
6	ZIMAXW	Maximum over-water mixing height (m)	3000	3000
6	ZIMIN	Minimum over-land mixing height (m)	50	50
6	ZIMINW	Minimum over-water mixing height (m)	50	50

APPENDIX D
CALPUFF Parameter Values

Appendix D
CALPUFF Parameter Values

Table D-1 Recommended CALPUFF Parameters chosen by EPA Region 10 states for use in BART modeling.

Input Group	Group Description	Sequence	Variable	Description	Default Value[a]	Recommended Value
1	Run Control	1	METRUN	Do we run all periods (1) or a subset (0)?	0	
1		2	IBYR	Beginning year	User Defined	
1		3	IBMO	Beginning month	User Defined	
1		4	IBDY	Beginning day	User Defined	
1		5	IBHR	Beginning hour	User Defined	
1		5	IRLG	Length of run (hours)	User Defined	
1		5	NSECDT	Length of modeling time step (seconds)	3600	3600
1		6	NSPEC	Number of species modeled (for MESOPUFF II chemistry)	5	
1		7	NSE	Number of species emitted	3	
1		8	ITEST	Flag to stop run after Setup Phase	2	
1		9	MRESTART	Restart options (0 = no restart) allows splitting runs into smaller segments	0	
1		10	NRESPD	Number of periods in Restart	0	
1		11	METFM	Format of input meteorology (1 = CALMET, 2 = ISC)	1	
1		12	AVET	Averaging time lateral dispersion parameters (minutes)	60	60
1		13	PGTIME	PG Averaging time	60	60
2	Tech Options	1	MGAUSS	Near-field vertical distribution (1 = Gaussian)	1	1
2		2	MCTADJ	Terrain adjustments to plume path (3 = Plume path)	3	3
2		3	MCTSG	Do we have subgrid hills? (0 = No) allows CTDM-like treatment for subgrid scale hills	0	0
2		4	MSLUG	Near-field puff treatment (0 = No slugs)	0	0
2		5	MTRANS	Model transitional plume rise? (1 = Yes)	1	1
2		6	MTIP	Treat stack tip downwash? (1 = Yes)	1	1
2		7	MBDW	Method to simulate downwash (1=ISC,2=PRIME)		not used
2		8	MSHEAR	Treat vertical wind shear? (0 = No)	0	0
2		9	MSPLIT	Allow puffs to split? (0 = No)	0	0
2		10	MCHEM	MESOPUFF-II Chemistry? (1 = Yes)	1	1
2		11	MAQCHEM	Aqueous phase transformation	0	0
2		12	MWET	Model wet deposition? (1 = Yes)	1	1
2		13	MDRY	Model dry deposition? (1 = Yes)	1	1
2		13	MTILT	Plume Tilt (gravitational settling)	0	0
2		14	MDISP	Method for dispersion coefficients (2=micromet,3 = PG)	3	3
2		15	MTURBVW	Turbulence characterization? (Only if MDISP = 1 or 5)	3	3
2		16	MDISP2	Backup coefficients (Only if MDISP = 1 or 5)	3	3
2		16	MTAULY	Method for Sigma y Lagrangian timescale	0	0
2		16	MTAUADV	Method for Advective-Decay timescale for Turbulence	0	0
2		16	MCTURB	Method to compute sigma v,w using micromet variables	1	1
2		17	MROUGH	Adjust PG for surface roughness? (0 = No)	0	0
2		18	MPARTL	Model partial plume penetration? (0 = No)	1	1
2		19	MTINV	Elevated inversion strength (0 = compute from data)	0	0
2		20	MPDF	Use PDF for convective dispersion? (0 = No)	0	0
2		21	MSGTIBL	Use TIBL module? (0 = No) allows treatment of subgrid scale coastal areas	0	0
2		22	MBCON	Boundary conditions modeled	0	0
2		23	MFOG	Configure for FOG model output	0	0
2		24	MREG	Regulatory default checks? (1 = Yes)	1	1

Table D-1 Recommended CALPUFF Parameters chosen by EPA Region 10 states for use in BART modeling.						
Input Group	**Group Description**	**Sequence**	**Variable**	**Description**	**Default Value[a]**	**Recommended Value**
3	Species List	1	CSPECn	Names of species modeled (for MESOPUFF II must be SO2-SO4-NOX-HNO3-NO3)	User Defined	
3		2	Specie Names	Manner species will be modeled	User Defined	
3		3	Specie Groups	Grouping of species if any	User Defined	
3		4	CGRUP			
3		5	CGRUP			
4	MapProjection		XLAT1	Latitude of 1st standard parallel		
4			XLAT2	Latitude of 2nd standard parallel		
4			DATUM			NWS84
4		1	NX	Number of east-west grids of input meteorology	User Defined	373
4		2	NY	Number of north-south grids of input meteorology	User Defined	316
4		3	NZ	Number of vertical layers of input meteorology	User Defined	10
4		4	DGRIDKM	Meteorology grid spacing (km)	User Defined	4
4		5	ZFACE	Vertical cell face heights of input meteorology	User Defined	0,20,40,65,120,200,400,700,1200,2200,4000
4		6	XORIGKM	Southwest corner (east-west) of input User	Defined meteorology	-572
4		7	YORIGIM	Southwest corner (north-south) of input User	Defined meteorology	-956
4		8	IUTMZN	UTM zone	User Defined	
4		9	XLAT	Latitude of center of meteorology domain	User Defined	
4		10	XLONG	Longitude of center of meteorology domain	User Defined	
4		11	XTZ	Base time zone of input meteorology	User Defined	
4		12	IBCOMP	Southwest X-index of computational domain	User Defined	105
4		13	JBCOMP	Southwest Y-index of computational domain	User Defined	79
4		14	IECOMP	Northeast X-index of computational domain	User Defined	242
4		15	JECOMP	Northeast Y-index of computational domain	User Defined	252
4		16	LSAMP	Use gridded receptors? (T = Yes)	F	F
4		17	IBSAMP	Southwest X-index of receptor grid	User Defined	
4		18	JBSAMP	Southwest Y-index of receptor grid	User Defined	
4		19	IESAMP	Northeast X-index of receptor grid	User Defined	
4		20	JESAMP	Northeast Y-index of receptor grid	User Defined	
4		21	MESHDN	Gridded recpetor spacing = DGRIDKM/MESHDN	1	
5	Output Options	1	ICON	Output concentrations? (1 = Yes)	1	1
5		2	IDRY	Output dry deposition flux? (1 = Yes)	1	1
5		3	IWET	Output west deposition flux? (1 = Yes)	1	1
5		4	IT2D	2D Temperature	0	0
5		5	IRHO	2D Density	0	0
5		6	IVIS	Output RH for visibility calculations (1 = Yes)	1	1
5		7	LCOMPRS	Use compression option in output? (T = Yes)	T	T
5		8	ICPRT	Print concentrations? (0 = No)	0	0
5		9	IDPRT	Print dry deposition fluxes (0 = No)	0	0
5		10	IWPRT	Print wet deposition fluxes (0 = No)	0	0
5		11	ICFRQ	Concentration print interval (1 = hourly)	1	24
5		12	IDFRQ	Dry deposition flux print interval (1 = hourly)	1	24
5		13	IWFRQ	West deposition flux print interval (1 = hourly)	1	24
5		14	IPRTU	Print output units (1 = g/m**3; g/m**2/s; 3 = ug/m3, ug/m2/s)	1	3
5		15	IMESG	Status messages to screen? (1 = Yes)	1	2
5		16	LDEBUG	Turn on debug tracking? (F = No)	F	F

Table D-1 Recommended CALPUFF Parameters chosen by EPA Region 10 states for use in BART modeling.

Input Group	Group Description	Sequence	Variable	Description	Default Value[a]	Recommended Value
5		16	IPFDEB	First puff to track	1	1
5		17	NPFDEB	(Number of puffs to track)	(1)	1
5		18	NN1	(Met. Period to start output)	(1)	1
5		19	NN2	(Met. Period to end output)	(10)	10
7	Dry Dep Chem		Dry Gas Dep	Chemical parameters of gaseous deposition species	User Defined	defaults
8	Dry Dep Size		Dry Part. Dep	Chemical parameters of particulate deposition species	User Defined	defaults
9	Dry Dep Misc	1	RCUTR	Reference cuticle resistance (s/cm)	30	30
9		2	RGR	Reference ground resistance (s/cm)	10	10
9		3	REACTR	Reference reactivity	8	8
9		4	NINT	Number of particle-size intervals	9	9
9		5	IVEG	Vegetative state (1 = active and unstressed; 2=active and stressed)	1	1
10	Wet Dep		Wet Dep	Wet deposition parameters	User Defined	defaults
11	Chemistry	1	MOZ	Ozone background? (0 = constant background value; 1 = read from ozone.dat)	0	0
11		2	BCKO3	Ozone default (ppb) (Use only for missing data)	80	60
11		3	BCKNH3	Ammonia background (ppb)	10	17
11		4	RNITE1	Nighttime SO2 loss rate (%/hr)	0.2	0.2
11		5	RNITE2	Nighttime NOx loss rate (%/hr)	2	2
11		6	RNITE3	Nighttime HNO3 loss rate (%/hr)	2	2
11		7	MH2O2	H2O2 data input option	1	1
11		8	BCKH2O2	Monthly H2O2 concentrations	1	12*1
			BKPMF	Fine particulate concentration	12 * 1.00	not used
			OFRAC	Organic fraction of Fine Particulate	2*0.15, 9*0.20, 1*0.15	not used
			VCNX	VOC / NOX ratio	12 * 50.00	not used
12	Dispersion	1	SYTDEP	Horizontal size (m) to switch to time dependence	550	550
12		2	MHFTSZ	Use Heffter for vertical dispersion? (0 = No)	0	0
12		3	JSUP	PG Stability class above mixed layer	5	5
12		4	CONK1	Stable dispersion constant (Eq 2.7-3)	0.01	0.01
12		5	CONK2	Neutral dispersion constant (Eq 2.7-4)	0.1	0.1
12		6	TBD	Transition for downwash algorithms (0.5 = ISC)	0.5	0.5
12		7	IURB1	Beginning urban landuse type	10	10
12		8	IURB2	Ending urban landuse type	19	19
12		9	ILANDUIN	Land use type (20 = Unirrigated agricultural land)	20	20
12		10	ZOIN	Roughness length (m)	0.25	0.25
12		11	XLAIIN	Leaf area index	3.0	3.0
12		12	ELEVIN	Met. Station elevation (m above MSL)	0.0	0.0
12		13	XLATIN	Met. Station North latitude (degrees)	-999.0	-999.0
12		14	XLONIN	Met. Station West longitude (degrees)	-999.0	-999.0
12		15	ANEMHT	Anemometer height of ISC meteorological data (m)	10.0	10.0
12		16	ISIGMAV	Lateral turbulence (Not used with ISC meteorology)	1	1
12		17	IMIXCTDM	Mixing heights (Not used with ISC meteorology)	0	0
12		18	XMXLEN	Maximum slug length in units of DGRIDKM	1.0	1
12		19	XSAMLEN	Maximum puff travel distance per sampling step (units of DGRIDKM)	1.0	1
12		20	MXNEW	Maximum number of puffs per hour	99	99
12		21	MXSAM	Maximum sampling steps per hour	99	99
12		22	NCOUNT	Iterations when computing Transport Wind (Calmet & Profile Winds)	2	2
12		23	SYMIN	Minimum lateral dispersion of new puff (m)	1.0	1
12		24	SZMIN	Minimum vertical dispersion of new puff (m)	1.0	1
12		25	SVMIN	Array of minimum lateral turbulence (m/s)	6 * 0.50	6 * 0.50

Table D-1 Recommended CALPUFF Parameters chosen by EPA Region 10 states for use in BART modeling.

Input Group	Group Description	Sequence	Variable	Description	Default Value[a]	Recommended Value
12		26	SWMIN	Array of minimum vertical turbulence (m/s)	0.20,0.12,0.08, 0.06,0.03,0.016	
12		27	CDIV (1), (2)	Divergence criterion for dw/dz (1/s)	0.01 (0.0,0.0)	0.0,0.0
12		28	WSCALM	Minimum non-calm wind speed (m/s)	0.5	0.5
12		29	XMAXZI	Maximum mixing height (m)	3000	3000
12		30	XMINZI	Minimum mixing height (m)	50	50
12		31	WSCAT	Upper bounds 1st 5 wind speed classes (m/s)	1.54,3.09,5.14, 8. 23,10.8	1.54,3.09,5.14,8. 23,10.8
12		32	PLX0	Wind speed power-law exponents	0.07,0.07,0.10, 0.15,0.35,0.55	0.07,0.07,0.10,0. 15,0.35,0.55
12		33	PTGO	Potential temperature gradients PG E and F (deg/km)	0.020,0.035	0.020,0.035
12		34	PPC	Plume path coefficients (only if MCTADJ = 3)	0.5,0.5,0.5,0.5, 0.35,0.35	0.5,0.5,0.5,0.5,0. 35,0.35
12		35	SL2PF	Maximum Sy/puff length	10.0	10.0
12		36	NSPLIT	Number of puffs when puffs split	3	3
12		37	IRESPLIT	Hours when puff are eligible to split	User Defined	
12		38	ZISPLIT	Previous hour's mixing height(minimum)(m)	100.0	100.0
12		39	ROLDMAX	Previous Max mix ht/current mix ht ratio must be less then this value for puff to split	0.25	0.25
12		40	NSPLITH	Number of puffs when puffs split horizontally	5	5
12		41	SYSPLITH	Min sigma-y (grid cell units) of puff before horiz split	1.0	1.0
12	12	42	SHSPLITH	Min puff elongation rate per hr from wind shear before horiz split	2.0	2.0
12		43	CNSPLITH	Min conc g/m3 before puff may split horizontally	1.0E-07	1.0E-07
12		44	EPSSLUG	Convergence criterion for slug sampling integration	1.00E-04	1.00E-04
12		45	EPSAREA	Convergence criterion for area source integration	1.00E-06	1.00E-06
12		46	DSRISE	Step length for rise integration	1.0	1.0
12		47	HTMINBC		500.0	500.0
12		48	RSAMPBC		10.0	10.0
12		49	MDEPBC		1	1
13	Point Source	1	NPT1	Number of point sources	User Defined	
13		2	IPTU	Units of emission rates (1 = g/s)	1	
13		3	NSPT1	Number of point source-species combinations	0	
13		4	NPT2	Number of point sources with fully variable emission rates	0	
13			Point Sources	Point sources characteristics	User Defined	
14	Area Source		Area Sources	Area sources characteristics	User Defined	
15	Volume Source		Volume	Volume sources characteristics	User Defined Sources	
16	Line Source		Line Sources	Buoyant lines source characteristics	User Defined	
17	Receptors		NREC	Number of user defined receptors	User Defined	
17			Receptor Data	Location and elevation (MSL) of receptors	User Defined	

APPENDIX E

CALPOST Parameter Values

Appendix E
CALPOST Parameter Values

Table E-1. Recommended CALPOST parameter values chosen by the Region 10 states for use in BART modeling

Input Group	Variable	Description	Default Value	Recommended Value
1	ASPEC	Species to process	VISIB	VISIB
1	ILAYER	Layer/deposition code (1 = CALPUFF concentrations; -3 = wet+dry deposition fluxes)	1	1
1	LBACK	Add Hourly Background Concentrations/Fluxes?	F	F
1	MFRH	Particle growth curve for hygroscopic species	2	2
2	RHMAX	Maximum relative humidity (%) used in particle growth curve	98	95
2	LDRING	Report results by Discrete receptor Ring, if Discrete Receptors used. (T = true)	T	
		Modeled species to be included in computing the light extinction		
2	LVSO4	Include SO4?	T	T
2	LVNO3	Include NO3?	T	T
2	LVOC	Include Organic Carbon?	T	T
2	LVPMC	Include Coarse Particles?	T	T
2	LVPMF	Include Fine Particles?	T	T
2	LVEC	Include Elemental Carbon?	T	T
2	LVBK	when ranking for TOP-N, TOP-50, and Exceedance tables Include BACKGROUND?	T	T
2	SPECPMC	Species name used for particulates in MODEL.DAT file: COARSE =	PMC	PMC
2	SPECPMF	Species name used for particulates in MODEL.DAT file: FINE =	PMF	PMF
		Extinction Efficiencies (1/Mm per ug/m**3)		
2	EEPMC	PM COARSE =	0.6	0.6
2	EEPMF	PM FINE =	1.0	1.0
2	EEPMCBK	Background PM COARSE	0.6	0.6
2	EESO4	SO4 =	3.0	3.0
2	EENO3	NO3 =	3.0	3.0
2	EEOC	Organic Carbon =	4.0	4.0
2	EESOIL	Soil =	1.0	1.0
2	EEEC	Elemental Carbon =	10.0	10.0
2	LAVER	Method used for 24-hr avg % change light extinction	F	F
2	MVISBK	Method used for background light extinction (2 = Hourly RH adjustment; 6 = FLAG seasonal f(RH))	2 or 6	6
2	RHFAC	Monthly RH adjustment factors from FLAG (unique for each Class I area)	Yes if 6	EPA
		Background monthly extinction coefficients (FLAG) unique for each Class I area		
2	BKSO4	Assume all hygroscopic species as SO4 (raw extinction value without scattering efficiency adjustment)		*see table*
2	BKNO3			*see table*
2	BKPMC			*see table*
2	BKOC			*see table*
2	BKSOIL	Assume all non-hygroscopic species as Soil		*see table*
2	BKEC			*see table*
2	BEXTRAY	Extinction due to Rayleigh scattering	10.0	10.0
		Averaging time(s) reported		
3	L1PD	Averaging period of model output	F	F
3	L1HR	1-hr averages	F	F
3	L3HR	3-hr averages	F	F
3	L24HR	24-hr averages	T	T
3	LRUNL	Run lengtyh (annual)	F	F
3	LT50	Top 50 table for each averaging time selected	T	F
3	LTOPN			1
3	NTOP			1
3	ITOP			

APPENDIX F

Emission Rates and Stack Parameters

PGE Boardman Unit 1 - Flue Gas Emissions Data

							PM$_{10}$ Speciation: Filterable			Condensable		
Baseline Case - Existing Operation	Flow (acfm)	Stack Velocity (ft/s)	Temp. (°F)	NO_x (lb/hr)	SO_2 (lb/hr)	PM_{10} (lb/hour)	Elemental Carbon (lb/hour)	PM Fine (lb/hour)	PM Coarse (lb/hour)	Organic Carbon (lb/hour)	Inorganic Aerosol (lb/hour)	Non-SO_2 Inor Aersol(lb/hour)
1. Existing Operation	2,159,900	95	293	3152.0	4943.1	176.20	1.74	45.40	58.90	14.00	56.10	0.00

NO_x Controlled Outlet Conditions	Flow (acfm)	Stack Velocity (ft/s)	Temp. (°F)	NO_x (lb/hr)	SO_2 (lb/hr)	PM_{10} (lb/hour)	Elemental Carbon (lb/hour)	PM Fine (lb/hour)	PM Coarse (lb/hour)	Organic Carbon (lb/hour)	Inorganic Aerosol (lb/hour)	Non-SO_2 Inor Aersol(lb/hour)
1. Selective Catalytic Reduction (SCR)	2,173,000	95	293	869.0	4943.1	176.20	1.74	45.40	58.90	14.00	56.10	0.00
2. New Low NO_x Burners with Modified OFA System	2,159,900	95	293	1332.4	4943.1	176.20	1.74	45.40	58.90	14.00	56.10	0.00

SO_2 Controlled Outlet Conditions	Flow (acfm)	Stack Velocity (ft/s)	Temp. (°F)	NO_x (lb/hr)	SO_2 (lb/hr)	PM_{10} (lb/hour)	Elemental Carbon (lb/hour)	PM Fine (lb/hour)	PM Coarse (lb/hour)	Organic Carbon (lb/hour)	Inorganic Aerosol (lb/hour)	Non-SO_2 Inor Aersol(lb/hour)
1. Wet Flue Gas Desulfurization (FGD)	1,823,200	60	136	3152.0	579.3	115.45	1.14	29.80	38.60	9.20	36.80	0.00
2. Semi-Dry Flue Gas Desulfurization (FGD)	1,901,700	83	170	3152.0	869.0	115.45	1.14	29.80	38.60	9.20	36.80	0.00

Notes:

1) SO_2 based on no SO_2 to SO_3 conversion.

2) PM speciations derived from spreadsheet prepared by ODEQ.

3) Stack velocity (except for Wet FGD and Wet ESP) based on existing stack diameter of 22 feet.

4) Emission rates based on 5,793 mmbtu/hr.

Rick Tetzloff - RE: Revised Protocol

From: "ALLEN Philip" <ALLEN.Philip@deq.state.or.us>
To: <Don.Caniparoli@CH2M.com>, <Mark.Fisher@state.or.us>
Date: 1/18/2007 6:06 PM
Subject: RE: Revised Protocol
CC: <Patty.Jacobs@state.or.us>, <Ray.Hendricks@pgn.com>, <Rick.Tetzloff@pgn.com>, <Steven.Anderson@pgn.com>, <natalie.liljenwall@ch2m.com>

Don,

The revised protocol for the BART-Determination Calpuff modeling for the PGE Boardman facility, as submitted, includes:

1) A summary of the BART Modeling Protocol for Washington, Oregon, and Idaho (2006), which was developed by the three states to cover both the Exemption and Determination phases of the modeling,
2) Engineering data on possible controls, with a proposed set of four controls and their respective emission rates and stack parameters that will be evaluated in the Determination modeling.

In that the Calpuff modeling portion of the revised Boardman protocol summarizes and highlights the approved Modeling Protocol for Washington, Oregon, and Idaho, the modeling portion of the revised protocol is approved for use in the Determination or control evaluation phase of the BART analysis.

Phil

Philip Allen
AQ Division
Oregon DEQ
503.229.6904
allen.philip@deq.state.or.us

-----Original Message-----
From: Don.Caniparoli@CH2M.com [mailto:Don.Caniparoli@CH2M.com]
Sent: Wednesday, January 17, 2007 4:44 PM
To: ALLEN Philip; Mark.Fisher@state.or.us
Cc: Patty.Jacobs@state.or.us; Ray.Hendricks@pgn.com; Rick.Tetzloff@pgn.com; Steven.Anderson@pgn.com; natalie.liljenwall@ch2m.com
Subject: Revised Protocol

Attached is the revised protocol as we discussed today.

Don

From: ALLEN Philip [mailto:ALLEN.Philip@deq.state.or.us]
Sent: Tuesday, August 28, 2007 12:21 PM
To: ray.hendricks@pgn.com
Cc: Caniparoli, Don/PDX; FISHER Mark
Subject: Use of onzone.dat file for BART

Ray,
As you know, an ozone.dat for use in the Calpuff BART Exemption modeling was developed by Eri Ottersburg (SLR, International) and Mary Beth Yansura (CH2M Hill), with input and review by Oregon DEQ. This file would be used in lieu of the default 60 ppb value that was specified in the three-states BART Modeling Protocol. The ozone data incorporated in the file was compiled from state and federal ozone monitors in the three state area. After discussions with EPA Region 10, the Federal Land Managers (Forest Service, U.S. Fish and Wildlife, and National Park Service), and Washington State and Idaho, this ozone.dat file is considered an addition to the protocol and acceptable for use in the BART modeling.

If you have any questions, please don't hesitate to contact me.

Phil

Philip Allen
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Oregon DEQ
503.229.6904
allen.philip@deq.state.or.us

Public Comment Invited

DEQ to Propose Denial of PGE's Petition to Amend Regional Haze Rules

Recommended action

DEQ plans to recommend that the Oregon Environmental Quality Commission deny PGE's petition to reduce the stringency of regional haze pollution controls for the PGE Boardman coal-fueled electric generating plant as part of a proposal to close the plant by Dec. 31, 2020.

While DEQ supports an early shut down, the agency is interested in exploring a range of options and then proposing a rule allowing for early closure. Accepting PGE's petition would lock in only one approach as the starting point in the rule making.

DEQ plans to complete an evaluation of pollution control requirements consistent with an early shut down and all applicable federal requirements.

DEQ plans to recommend that the commission deny PGE's petition at the June 17th commission meeting.

DEQ and the commission are interested in hearing from the public and are opening a public comment period for written comments immediately until June 1. The commission will also hold a public hearing at its June 17 meeting and take oral comments.

If the commission denies the petition, DEQ will propose revised regional haze rules for consideration at the commission's meeting in December 2010 following a complete rulemaking process that would include stakeholder meetings, an advisory committee meeting, a public comment period, and one or more public hearings.

How to comment

Comments are invited on DEQ's plan to recommend denial of PGE's petition.

Public comments at this time should focus only on DEQ's plan to recommend denial of PGE's petition. If the commission decides to accept the recommendation and initiate a rulemaking, DEQ will begin another public process to discuss and take comments on any rulemaking proposal.

Pursuant to OAR 137-001-0070(3), public comment is also invited on the regional haze pollution control rules applicable to the Boardman plant (OAR 340-223-0030 and 340-223-0040), and on whether options exist for achieving the substantive goals of the rules in a way that reduces the negative economic impact on businesses.

Comments may be submitted in writing via mail, fax or e-mail at any time prior to the comment deadline of 5:00 pm, June 1, 2010. Oral comments may be provided at the commission's meeting on June 17, 2010.

Written comments may be emailed to PGErulepetition@deq.state.or.us, mailed or faxed to Brian Finneran, Oregon DEQ, Air Quality Division, 811 SW 6th Avenue, Portland, Oregon 97204, fax: (503) 229-5675, and phone (503) 229-6278, or toll-free in Oregon at 1-800-452-4011.

DEQ sends an auto-acknowledgment for e-mail comments, which must be limited to 10 MB, including attachments. People should contact DEQ staff if they do not receive an automatic response, or the comments and attachments exceed the limit. If there is a delay between servers, e-mails may not be received before the deadline.

Why might rule changes be needed?

PGE proposes to shut down the Boardman coal-fired power plant by the end of 2020. The early shutdown date affects the pollution control requirements for the plant, and may allow for less stringent controls due to early shutdown. Federal law requires the commission to determine the pollution control requirements based upon a number of factors, including cost. A plant that operates longer can spread the cost of pollution controls over more years, and may be required to install certain controls, while the same controls might not be required for a plant that operates for fewer years.

Who may be affected?

PGE, persons who live and recreate in areas impacted by the coal-fired power plant, as well as PGE rate payers.

Why wasn't early closure incorporated into the regional haze rules?

The commission received comments from PGE during the 2009 regional haze rulemaking requesting alternative pollution control technology requirements based on early closure of the Boardman plant. The commission did not grant the request in the rules it adopted because PGE's request did not include a complete pollution control analysis for early closure as required by federal law. The commission did, however, commit to take action on a future request by PGE to revise the rules based on an early shut down of the plant provided PGE submits a complete pollution control analysis.

On April 2, 2010, PGE submitted a petition to amend the regional haze rules based on early closure. PGE's petition for revising the regional haze rules can be reviewed online or at DEQ's office at 811 S.W. 6th Avenue, Portland, Oregon. Please contact

Brian Finneran for times when the documents are available for review.

Additional materials available

- OAR 340-011-0046
- OAR 137-001-0070

These Oregon Administrative Rules govern how the commission must respond to petitions to amend its administrative rules.

Public hearing on June 17

A public hearing will be held in Lakeview at **the Environmental Quality Commission's regularly scheduled meeting on June 17** in Lakeview, OR. The hearing will begin at 8:30 a.m. with a brief overview of the proposed action, followed by the opportunity for members of the public to provide oral comment to the commission prior to the commission's action on PGE's petition and DEQ's recommendations.

Elk's Lodge
323 N F St.
Lakeview, Oregon

For convenience, DEQ will have conference rooms available at its offices in Bend, Eugene, Medford, Portland and Pendleton equipped to allow the public to provide oral comments. People who wish to comment before the commission are encouraged to choose the nearest location:

Bend
Main Conference Room
475 NE Bellevue

Eugene
Willamette Conference Room
165 East 7th Avenue, Suite 100

Medford
Main Conference Room
221 Stewart Avenue, Suite 201

Pendleton:
Main conference room
700 SE Emigrant, #330

Portland:
Conference room EQC A
10th Floor
811 SW 6th Avenue

The Dalles
DEQ office at
Columbia Gorge Community College
400 E Scenic Drive, Building 2

Written comment deadline: June 1, 2010

All written comments are due to DEQ by 5 p.m., June 1, 2010. DEQ cannot consider written comments from any party **received** after the deadline for public comment. Oral comments will be considered at the commission's meeting on June 17, 2010.

How will the commission take action on the petition and DEQ's recommendations?

DEQ will prepare a response to all comments received during the written comment period and may modify its proposed recommendations accordingly. DEQ plans to recommend that the commission deny PGE's petition, but initiate a subsequent rulemaking to revise the regional haze rules and establish the proper level of pollution control requirements for the Boardman plant as part of an early shut down. The commission will take action on the petition and DEQ's recommendations at the June 17, 2010 meeting in Lakeview after the public hearing.

Accessibility information

DEQ is committed to accommodating people with disabilities. Please notify DEQ of any special physical or language accommodations or if you need information in large print, Braille or another format. To make these arrangements, contact DEQ Communications and Outreach at (503) 229-5696 or call toll-free in Oregon at (800) 452-4011; fax to (503) 229-6762; or e-mail deqinfo@deq.state.or.us.

People with hearing impairments may call 711.