Air Quality Division

State of Oregon
Department of Environmental Quality

DEQ BART Report for the Boardman Power Plant

Updated December 19~~November 7~~, 2008

Update consists of following:
Page 6, link added to ERG Report.
Page 19, correction to Table 15.
Page 20, addition to Table 16.
Page 23, minor change under Cost-Benefit Analysis, and link added to BART Cost Spreadsheet.
Page 25, minor edit and link added to BART Modeling Spreadsheet.
Page 29, minor clarification made.

Executive Summary

In accordance with the Federal Clean Air Act, the Regional Haze rules and EPA's Guidelines (40 CFR 51.308 and Appendix Y), the Department of Environmental quality (Department) recommends the following Best Available Retrofit Technologies (BART), or equivalent technologies, for the coal fired steam electric generating unit at Portland General Electric's (PGE) power plant near Boardman, OR (Boardman Plant).

Pollutant	Control Technology	Emission Limit	Averaging Time	Installation Date
Nitrogen oxides (NO_x)	New low NO_x burners with modified overfire air system (NLNB/MOFA)	0.28 lb/mmBtu heat input	30-day rolling average	7/1/11
		0.23 lb/mmBtu heat input	12-month rolling average	7/1/11
	Selective Non-Catalytic Reduction (SNCR) contingency	0.23 lb/mmBtu heat input	30-day rolling average	7/1/14
Sulfur dioxide (SO_2)	Semi-dry flue gas desulfurization (SDFGD)	0.12 lb/mmBtu heat input	30-day rolling average	7/1/14
Particulate Matter (PM)	Pulse jet fabric filter (PJFF) as part of the SDFGD system and in addition to the existing electrostatic precipitator	0.012 lb/mmBtu heat input	3-hour average based on the results of compliance source testing	7/1/14

The SNCR contingency is included with BART in the event that new low NO_x burners with modified overfire air cannot achieve 0.23 lb/mmBtu heat input. The Department also recommends a phase 2 (beyond BART) NO_x emission reduction to 0.07 lb/mmBtu heat input (30-day rolling average) based on installation of a selective catalytic reduction system (or equivalent) by July 1, 2017. This additional control requirement is recommended in order to minimize Boardman's NO_x emissions to ensure that reasonable progress is being made to meet the regional haze goals for Class I Wilderness Areas and National Parks and to further improve the air quality and scenic vistas in the Columbia River Gorge National Scenic Area.

It is estimated that the capital cost of Phase I will be 280 million dollars with an annualized cost of 40.3 million dollars per year (2007 dollars). Phase 2 for NO_x will add an additional capital cost of 191 million dollars with an annualized cost of 23.1 million dollars (2007 dollars).

It is estimated that the proposed emission reductions will provide the following air quality benefits:

	BART **(NO_x only)**	**BART** **(NO_x, SO_2, PM)**	**Phase 2** **(NO_x, SO_2, PM)**
Date	7/1/2011	7/1/2014	1/1/2018
Total emission reductions (NO_x, SO_2, PM - tons/yr)[1]	4,800 (19% reduction)	16,900 (66% reduction)	20,800 (81% reduction)
Mt. Hood[2] visibility impacts (98th percentile)[3][4]	4.0 dv[5] (13% improvement)	2.5 dv (45% improvement)	1.0 dv (78% improvement)
Days/year >1.0 delta dv (most frequently impacted Class I area)[6]	55 (13% improvement)	34 (46% improvement)	7 (89% improvement)
Number Class I Areas >1.0 delta deciview[7]	12	5	0
Average Class I Area visibility impacts	2.0 dv (11% improvement)	1.1 dv (52% improvement)	0.4 dv (81% improvement)
Total visibility impacts (sum of 98th percentile for all Class I areas)[8]	26.5 dv (15% improvement)	13.8 dv (56% improvement)	5.5 dv (82% improvement)
Columbia River Gorge visibility impacts (98th percentile)[9]	3.2 dv (13% improvement)	2.1 dv (44% improvement)	0.8 dv (78% improvement)
Columbia River Gorge days/year >1.0 delta dv impact[10]	53 (8% improvement)	34 (41% improvement)	3 (94% improvement)
Average improvement for all metrics	13%	50%	83%

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[1] Rounded to the nearest 100 tons, baseline equals 25,700 tons/yr

[2] Mt Hood is the closest Class I Wilderness Area to the Boardman plant and it has the highest impacts.

[3] The 98th percentile is the 22nd highest daily value for the three year period of 2003 through 2005.

[4] Baseline equals 4.6 deciviews

[5] A deciview (dv) is a measure of visibility impairment. A 0.5 deciview change equals about a 5% change in visible range (e.g., how far one can see) and is barely perceptible by about 50% of the observers. A 1.0 deciview change is perceptible by almost all observers. Deciviews and percent change in visible range are approximately linear in the lower end of the scale. A delta deciview is the change in deciviews relative to natural visibility background.

[6] Baseline equals an average of 63 days in Hells Canyon during the 2003 through 2005 period.

[7] 14 Class I Wilderness Areas and National Parks within 300 km of the Boardman plant were modeled. Other Class I areas farther from the power plant may be impacted, but the impacts would be less than presented in the table.

[8] Baseline equals 31.1 deciviews

[9] Baseline equals 3.7 deciviews

[10] Baseline equals 58 days/year

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INTRODUCTION

Federal regulations under 40 CFR 51.308 require each state to submit a regional haze plan that includes a determination of Best Available Retrofit Technology (BART) for each BART-eligible source in the State that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. In determining BART, each state shall take into consideration the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. On July 6, 2005, EPA promulgated guidelines for BART determinations under the regional haze rule as Appendix Y to 40 CFR Part 51. Although not specifically required to follow these guidelines, the Department has opted to follow the guidelines for the sake of national consistency. The BART guidelines were designed to help states and others (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.

Based on the guidelines, the Department determined that the PGE Boardman coal fired power plant is a BART eligible source because it is within one of the 26 source categories identified in the regulations (specifically, fossil-fuel fired steam electric generating plants of more than 250 million British thermal units per hour heat input), commenced construction after August 7, 1962 and prior to August 7, 1977, and has potential emissions greater than 250 tons per year of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM).

In coordination with the states of Washington and Idaho, the federal land managers, and EPA, a monitoring protocol was developed for determining whether a BART-eligible source is subject to BART. The protocol specified the modeling programs (CALMET, CALPUFF, and CALPOST), meteorology (MM5), time period (years 2003 through 2005), range of influence (300 kilometers) and source emissions levels (highest 24-hour average emissions) to be used for assessing visibility impacts on Federal Class I areas. In addition, the protocol specified that any BART-eligible source with a delta impact greater than 0.5 deciview based on the 22nd highest day for the three year period or 8th highest day for any one year contributes to visibility impairment and is subject to BART. Using the model and actual emissions, it was determined that the Boardman plant had an impact above natural background of 4.6 deciviews within the Mt. Hood Wilderness area and the impacts were greater than 0.5 deciview in all 14 Federal Class I areas modeled. Based on the results of the model, the Department concluded that the Boardman plant is subject to BART.

On November 2, 2007, PGE submitted a BART Analysis that was based on the BART guidelines. In response to comments, PGE amended the analysis on March 25, 2008. The analysis identified the following controls as BART:

Table 1: PGE BART Proposal

Pollutant	Control Technology	Emission Rate
Sulfur dioxide	Semi-dry flue gas desulfurization	0.12 lb/mmBtu
Nitrogen oxides	New low-NO_x burners with modified overfire air system and selective non-catalytic reduction	0.23 lb/mmBtu
Particulate matter	Pulse jet fabric filter	0.012 lb/mmBtu

PGE's BART analysis and proposal provided a very useful starting point for the Department's independent assessment of BART control options. The Department engaged Eastern Research Group, Inc. (ERG) to assist in its evaluation of the PGE proposal and to conduct an independent feasibility and cost assessment of select options for control of nitrogen oxides.

PGE's BART analysis was made available to interested stakeholders for their review and comments. The initial kick-off meeting was held in Portland on February 4, 2008. A significant number of questions and comments were provided by NEDC, PEAC, National Parks, Forest Service, and EPA. PGE provided responses to the questions and comments on March 25, 2008. In addition, PGE met with the Department and ERG several times to provide additional information related to the cost of control technologies.

ERG evaluated emission control options and emission performance information from EGU's projects around the county. ERG employed several methods to estimate the likely costs of different control options, including using industry-standard cost estimation models, literature searches of costs incurred in similar projects across the county, and discussions with PGE's contractor Black & Veatch to explore "real-world" costs for these types of projects. ERG's full report ~~to the Department is included as Appendix A.~~can be found on DEQ's Regional Haze website.[11]

The Department has carefully reviewed ERG's report, as well as information provided by all parties and makes the following recommendations for BART based on the statutory requirements and the BART guidelines, as discussed in this document. The SNCR contingency is included with BART in the event that new low NO_x burners with modified overfire air cannot achieve 0.23 lb/mmBtu heat input. This allows time for PGE to install the new low NO_x burners and modified overfire air system and evaluate the performance to determine whether SNCR is necessary to meet the BART presumptive limit.

Table 2: DEQ BART Proposal

Pollutant	Control Technology	Emission Limit	Averaging Time
Nitrogen oxides (NO_x)	New low NO_x burners with modified overfire air system (NLNB/MOFA)	0.28 lb/mmBtu input	30-day rolling average
		0.23 lb/mmBtu input	12-month rolling avg.
	Selective non-catalytic reduction (SNCR) contingency	0.23 lb/mmBtu input	30-day rolling average
Sulfur dioxide	Semi-dry flue gas desulfurization	0.12 lb/mmBtu input	30-day rolling average

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[11] See ERG's Technical Memorandum #2, June 26, 2008

(SO_2)	(SDFGD)		
Particulate Matter (PM)	Pulse jet fabric filter (PJFF) in addition to the existing ESP	0.012 lb/mmBtu input	3-hour average

SOURCE DESCRIPTION

PGE's coal fired steam electric generating unit near Boardman, Oregon commenced construction in 1975 and began operation in 1980. The unit is a Foster Wheeler dry bottom opposing wall fired design with first generation low NO_x burners and overfire air. To this date, only low-sulfur (~0.3% by weight) sub-bituminous coal from the Powder River Basin in Wyoming has been burned in the boiler, although other types of coal could be fired. The coal is delivered by train, unloaded to a storage pile, conveyed to pulverizes, mixed with heated combustion air and burned in the furnace. The heat from combustion is transferred to water in boiler tubes within the furnace and economizer to produce high pressure steam that drives a turbine that is connected to a generator to produce electricity. The unit is designed to burn 350 tons of coal per hour to produce approximately 617 Megawatts (MWe) of electricity per hour (gross).

When the coal is burned, exhaust gas is produced that contains particulate matter, nitrogen (71%), carbon dioxide (12%), water (10%), oxygen (7%), and less than 1% combination of sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds, and other acid gases (hydrochloric acid and hydrofluoric acid). At full load, the exhaust gas flow rate is about 2.3 million cubic feet per minute. An electrostatic precipitator (ESP) removes about 98% of the particulate matter before the exhaust gas is discharged to the atmosphere via a 650 feet tall stack. Due to the height of the stack, the velocity of the gases, and the temperature, the exhaust gas and pollutants are diluted and transported a considerable distance from the plant (300 to 500 kilometers or more, depending on the meteorological conditions). Once the gases enter the atmosphere, the sulfur dioxide and nitrogen oxides begin to react with background ammonia to form ammonium sulfates and nitrates, which are visibility impairing particles in addition to the fine particulate matter that is emitted directly from the source.

The Boardman Plant was originally permitted in 1977 and began operations in 1980. The emissions limits and standards that currently apply to the facility are as follows:

Table 3: Current emission limits and 2007 actual emissions

Pollutant	Emission limits		2007 actual emissions (tons/year)
	(lb/mmBtu)	(tons/year)	
Particulate matter	0.04	1,056	853
Nitrogen oxides	0.46	12,687	10,656
Sulfur dioxide	1.2	30,450	14,037

BART DETERMINATION PROCESS

The Department acknowledges that BART is intended to identify "retrofit" technology for existing sources and is not a top down analysis as required for new sources when determining Best Available Control Technology (BACT). The Department believes that had congress intended the application of BACT within the regional haze program, it would have stated so in the Clean Air Act. Although the Department believes that BART is not the same as BACT, it is possible that BART may be equivalent to BACT on a case-by-case basis.

As stated in the introduction, the Department has opted to follow EPA's guidelines to the extent possible for identifying BART. Accordingly, there are five basic steps for a case-by-case BART analysis:

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

In addition to the five steps provided above, EPA established presumptive BART emission limits for coal fired electric generating units greater than 200 megawatts located at greater than 750 MW power plants. Although the Boardman plant is not greater than 750 MW, the coal fired electric generating unit is greater than 200 MW, so the Department considers BART to be at least as stringent as the presumptive limits established by EPA. The BART presumptive limits for a dry bottom wall fired unit burning sub-bituminous coal are 0.15 lb/mmBtu heat input for sulfur dioxide and 0.23 lb/mmBtu heat input for nitrogen oxides.

The Department used PGE's 2007 BART analysis and proposal as a starting point for evaluating emission control options at the Boardman facility. The Department and its contractors ERG independently evaluated PGE's information and confirmed, or in some cases rejected, PGE's findings.

Step 1: Identify all available retrofit control technologies

PGE identified the following available retrofit control technologies:

Table 4: NO_x Control Technologies:

Technology	Description
Existing overfire air system (OFA) operation	OFA works by reducing the excess air in the burner zone to enhance the combustion staging effect that reduces NO_x emissions. The Boardman plant is equipped with OFA ports. However, because of extensive slagging issues and poor operability, the OFA ports are only opened on an as-needed basis. In order to aggressively operate the OFA system, a NO_x control system would have to be installed, as well as a water cannon system to reduce slagging.
Upgraded low NO_x burners (LNB)	There have been advances in LNB technology that may be applicable to the older generation LNBs at the Boardman Plant. Modifications such as to the fuel injector and combustion air swirlers along with proper balance of fuel and air flow can be made to increase NO_x reduction.
Upgraded LNB and existing OFA operation	NO_x reduction can be increased by combining upgrades to the LNBs and operating the OFA system.
Selective non-catalytic reduction (SNCR)	SNCR systems reduce NO_x by injecting reagent (ammonia or urea) at multiple levels within the boiler to react with the NO_x where the flue gas temperature ranges from 1,500

Technology	Description
	to 2,200° F. SNCR systems rely solely on reagent injection (rather than a catalyst), appropriate reagent injection temperature, good reagent/gas mixing, and adequate reaction time.
Upgraded LNB and existing OFA operation with SNCR	LNBs, OFA, and SNCR technologies can be combined to provide an overall reduction of NO_x emissions greater than can be achieved by the individual technologies.
New low NO_x burners and modified OFA system	This alternative includes the replacement of the existing LNB with new LNBs with modified OFA technologies close-coupled to provide an overall emission reduction better than upgraded LNBs and existing OFA operation.
New LNB with modified OFA and SNCR	The combination of new LNB and modified OFA system with SNCR may achieve lower emission reductions than can be achieved by the individual technologies.
Selective catalytic reduction (SCR)	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 catalyst. The NO_x and ammonia react to form nitrogen and water vapor. The SCR ammonia-catalytic reaction requires a temperature range of 600-750° F to be effective. As such, the SCR must be located after the convective pass of the boiler but before the air preheater.
New LNB with modified OFA and SCR	The combination of New LNB and modified OFA system with SCR would achiever the same emission reduction as SCR by itself, but has the added benefits of reducing NO_x in the event of SCR failure and would require less ammonia reagent.
SNCR/SCR hybrid (cascade)	The SNCR/SCR hybrid system has components and operating characteristics of both SNCR and SCR. Hybrid systems were developed to combine the low capital cost and high ammonia slip associated with SNCR systems with the high reduction potential and low 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.
Mobotect ROFA and ROTAMIX	Mobotec provides a NO_x reduction system that combines LNB, OFA, and SNCR technologies into an integrated system. The system uses a modified OFA system with mixing characteristics achieved through adding a rotation to the OFA (rotating opposed firing air, or ROFA).
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 principal, the OFA and SNCR processes are combined in this technology.
Induced flue gas recirculation (IFGR)	Injection of flue gas into the combustion air is a proven method for controlling NO_x production from gas-fired utility boilers. IFGR acts to reduce NO_x formation by reducing the peak flame temperatures.
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 flue gas desulfurization (FGD) system. The ozone reacts with the NO and NO_2 to form nitrogen pentoxide (N_2O_5) that is soluble in water and can be removed by the wet FGD.
Natural gas reburn	This system uses natural gas to create three combustion zones. Coal with slightly more excess air is burned in the primary zone. Natural gas with slightly less excess air (e.g., fuel rich) is burned in the reburning zone where NO_x formed in the primary zone is reduced to nitrogen. The final burnout zone utilizes normal overfire air.

Table 5: Sulfur dioxide control technologies:

Control Technology	Description
Wet flue gas desulfurization (Wet FGD)	Wet (limestone) FGD consist of reagent storage and handling system, FGD spray tower absorber, and byproduct dewatering system. Flue gas enters the absorber and is contacted with a slurry containing reagent and byproduct solids. The SO_2 is absorbed

Control Technology	Description
	into the slurry and reacts with the calcium (lime) to form both calcium sulfite and calcium sulfate.
Semi-dry flue gas desulfurization (semi-dry FGD)	Semi-dry FGD is based on the spray drying of lime slurry into flue gas in a spray dryer vessel. The SO_2 is absorbed into the fine spray droplets and reacts with the lime slurry to form both calcium sulfite and calcium sulfate. 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 which are collected in a pulse jet fabric filter.
Circulating dry scrubber	CDS is a form of dry FGD for SO_2 removal. Hydrated lime ($CA[OH]_2$) is introduced into the flue gas in a scrubber vessel as a dry, fee flowing powder which reacts with the SO_2 and the byproducted is collected in a particulate control device.
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 magnesium oxide to remove SO_2. This technology is typically capable of removing 20 to 50 percent of the SO_2 in the flue gas. 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.

Table 6: Particulate matter control technologies:

Control Technology	Description
Existing electrostatic precipitator (ESP) with operational restrictions	The Boardman plant is currently equipped with a cold-side ESP. To improve performance of the ESP to achieve lower PM emissions than the current permitted limit, operational restrictions such as minimizing the range in characteristics of the type of coal burned at the unit and increased use of the flue gas conditions system could consistently produce slightly lower PM emissions.
Pulse jet fabric filter (PJFF)	Fabric filters are media (cloth) filters that the flue gas passes through to remove particulate matter. The media is typically sewn into cylindrical tubes called bags. The bags are cleaned 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 and the particulate matter falls into a hopper
Compact hybrid particulate collector (COHPAC)	COHPAC is a high air to cloth ratio fabric filter installed after an existing cold-side ESP.
GE MAX-9 hybrid	The Max-9 electrostatic filter is a hybrid combination of a high efficiency pulse jet fabric filter and an ESP without collecting plates.
Multi-cyclone	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. Cyclone collectors are centrifugal collectors that rely on the particle density and velocity to separate the fly ash from the flue gas.
Wet ESP	A wet ESP 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 matter.

Table 7: Emerging Pollution Control Technologies:

Control Technology	Description
PowerSpan	The PowerSpan ECO system is located downstream of an existing particulate control device and 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. Stage 2 is the collection

Control Technology	Description
	of the acids and oxides in an ammonia scrubber. The final stage is the collection of acid aerosols, fine PM, and oxidized mercury a wet ESP.
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. A sorbent made up of oxides of manganese called Pahlmanite sorbent is injected upstream of spray dry absorber where the flue gas mixes with Pahlmanite sorbent. Mercury is oxidized and absorbed as well as SO_2 and NO_x. The byproducts are then separated from the flue gas in a pulse jet fabric filter.
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 emission when coal is burned. The only reagent required for pollution control is limestone. Limestone is mixed with the pulverized coal and burned in a high temperature fuel-rich combustion zone which releases all the constituents of coal into the gas (i.e., carbon, sulfur, nitrogen, and ash compounds). At these high temperatures and limited oxygen, the carbon aggressively commands oxygen to form carbon monoxide. The sulfur reacts with the lime to form calcium sulfide and the nitrogen passes through as inert nitrogen. Hydrocarbons are converted to carbon monoxide and hydrogen which are then burned in a second overfire air chamber to convert the CO to CO_2 and hydrogen to water.
J-Power ReACT System	Ammonia is injected into the flue gas prior to an activated carbon adsorber. The SO_2, SO_3, NO_x, mercury, and additional particulates are removed in the adsorber in one step and the pollutant saturated activated carbon is regenerated in a regenerator.

Provided below are other control technologies proposed by interested stakeholders:

Table 8: Other control technologies considered:

Control Technology	Description
Tail end SCR	This is the same concept as a hot side SCR, except that the control device is located downstream of the particulate matter controls which means that the exhaust gas has to be reheated with steam or natural gas combustion prior to the catalyst.
Oxygen enhanced combustion (OEC)/Praxair oxygen transport membrane (OTM)	Praxair, Inc. and its partners developed a novel oxygen enhanced combustion (OEC) technology that can reduce NO_x emissions from pulverized coal-fired boilers, while improving combustion characteristics such as loss-on-ignition. This novel technology replaces a small fraction of the combustion air with oxygen. Praxair is also developing an oxygen transport membrane process that uses pressurized ceramic membranes for separation of oxygen from air. Pilot-scale testing conducted using commercially-available wall-fired burner with OEC demonstrated less than 0.15 lb/mmBtu NO_x emissions could be achieved while firing Illinois No. 6 bitumion coal.
Ammonia free SCR (AF-SCR)	AF-SCR has the potential to reduce both capital and operating costs, and enhance performance operation and safety, by system-level integration and redesign of both in-furnace and post-combustion NO_x control steps. It optimizes the burner and the furnace to achieve very low NO_x levels and to provide an adequate amount of CO for reducing NO both in-furnace and over a downstream ammonia-free selective catalytic reduction reactor. The AF-SCR combines the advantages of the highly successful SCR technology for power plants and the three-way catalytic converter widely use in the automobile industry. Like the SCR, it works in oxidizing environment of combustion flue gas and uses only base metal catalysts. AF-SCR removes NO and excess CO simultaneously without using any external reagent, such as ammonia. The AF-SCR technology is well suited for new low NO_x burners because they generate excess CO that can be used to reduce the remaining NO to N_2 and carbon dioxide over the catalyst.

The Department reviewed numerous sources of information to confirm whether the list of control technology options provided above is sufficient for the BART determination process. These sources included, but were not limited to EPA's RACT/BACT/LAER clearing house, the Clean Air Markets Division database, New Source Performance Standards, Institute of Clean Air Companies, Department of Energy research documents, BART analysis for other coal-fired electric generating units, boiler manufacturer websites, pollution control technology vendor websites, Western Regional Air Partnership (WRAP) reports, and ERG's evaluation of PGE's BART analysis. Based on these sources of information, the Department has concluded that the list of control technology options is adequate.

Step 2: Eliminate technically infeasible options

According to EPA's BART guidelines, control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability". A control technique is considered available if it has reached the stage of licensing and commercial demonstration. This precludes technologies in the pilot scale testing stages of development. A control technique is "applicable" if it has been demonstrated in practice for the type of source undergoing the BART review; or, it has been demonstrated in practice for a similar type of source and the control technique could be applied to the type of source undergoing the BART review. Based on this guidance, the Department has determined that the following control devices are not technically feasible:

Table 9: Technically infeasible control options

Control Technology	Reason for not being technically feasible
Mobotec ROFA and RotoMIX	This technology is not considered technically feasible because there are no current installations at pulverized coal fired boilers of equivalent size to the Boardman plant. In addition, the ROFA technology is a variant of the OFA system that is being considered for BART.
NO_xStar and NO_xStar Plus	This technology requires natural gas, which is not available at the Boardman Plant.
ECOTUBE	This technology has not been demonstrated for the fuel type or the size range of the Boardman Plant.
Induced Flue Gas Recirculation	This technology is not generally applied to coal fired boilers. It is better suited for low nitrogen fuels, such as oil and natural gas.
$LoTO_x$	This technology has only been demonstrated for small-sized medical waste combustors.
Natural gas reburn	This technology requires natural gas, which is not available at the Boardman Plant.
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. Most applications of this technology are typically on circulating fluidized bed boilers and not pulverized coal boilers.
Furnace/Duct reagent injection	This technology has not been demonstrated for the size range of the Boardman Plant.
GE MAX-9 Hybrid	This technology has not been demonstrated for the size range of the Boardman Plant.
Multiple-Cyclone Collector	This technology is less efficient than the existing electrostatic precipitator.
PowerSpan	This technology has not been pilot tested in a low-sulfur coal burning facility or in a facility similar in size to the Boardman Plant.
Enviroscrub	This technology has not been demonstrated for the size range of the Boardman Plant.

Phenix clean coal	This technology has not been demonstrated for the size range of the Boardman Plant.
J-Power ReACT	This technology is still in the pilot scale development stage.
OEC/OTM	This technology has not been demonstrated for the size range of the Boardman Plant.
AF-SCR	This technology is still in the pilot scale development stage.

Step 3: Evaluate control effectiveness of remaining control technologies

PGE proposed the following control effectiveness for each of the technologies determined to be technically feasible. The Department added stand alone SCR for NO_x.

Table 10: Control Effectiveness

Pollutant	Control Technology	Control Effectiveness (lb/mmBtu heat input)
NO_x	Baseline	0.43
	Existing OFA system operation	0.40
	Upgraded LNBs	0.38
	SNCR	0.32
	Upgraded LNBs with existing OFA operation	0.32
	New LNBs with modified OFA system	0.28
	Upgraded LNBs with existing OFA system operation and SNCR	0.27
	New LNBs with modified OFA system and SNCR	0.23
	SCR	0.07
	New LNBs with modified OFA system and SCR	0.07
SO_2	Baseline	0.61
	Semi-dry FGD	0.12
	Wet FGD	0.09
PM	Baseline	0.017
	Existing ESP with operational restrictions	0.012
	PJFF	0.012
	COHPAC	0.012
	WESP	0.012

With the exception of New Low NOx Burners (LNB) with modified OFA system, the Department eliminated from further analysis those control technology options that could not meet the BART presumptive limit. This narrows the list of control options to the following:

Table 11: BART control options

Pollutant	Control Technology	Control Effectiveness (lb/mmBtu heat input)
NO_x	New LNBs with modified OFA system	0.28
	New LNBs with modified OFA system and SNCR	0.23
	Selective Catalytic Reduction (SCR)	0.07
	New LNBs with modified OFA system and SCR	0.07
SO_2	Semi-dry FGD	0.12
	Wet FGD	0.09
PM	Any control, but most likely PJFF	0.012

The Department considers the control effectiveness of a control technology to be equivalent to the permit limit that would be established for the control technology should it be selected as BART. The goal is to establish a limit that forces the use of a given technology, but can be achieved at all times provided the equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In establishing a permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability and more complex equipment and/or processes generally have greater variability. This variability must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

There are two components of an emission limit that address variability: 1) an upper limit based on the variability; and, 2) an averaging time that will allow the source to average the higher range of variability with lower range of variability. Provided the emissions variability is normally distributed (e.g., about half of the values are less than the average and half are greater than the average) and the emissions fluctuate up and down on a fairly regular basis, a good upper limit is the average plus two standard deviations, which statistically means that with about 95% confidence the emissions will be below the limit.

In reality, what typically happens is that in addition to the normal fluctuations, there are random spikes in emissions due to an operation glitch which can't be avoided even though the equipment is well maintained and properly operated. To address these spikes in emissions, an appropriate averaging time is used to damper the effects of the spikes. The result is that the emissions must be well below the emission limit for most of the time to ensure that the average, including the short duration spikes, will remain below the limit for all averaging periods. This is shown graphically for a hypothetical situation.

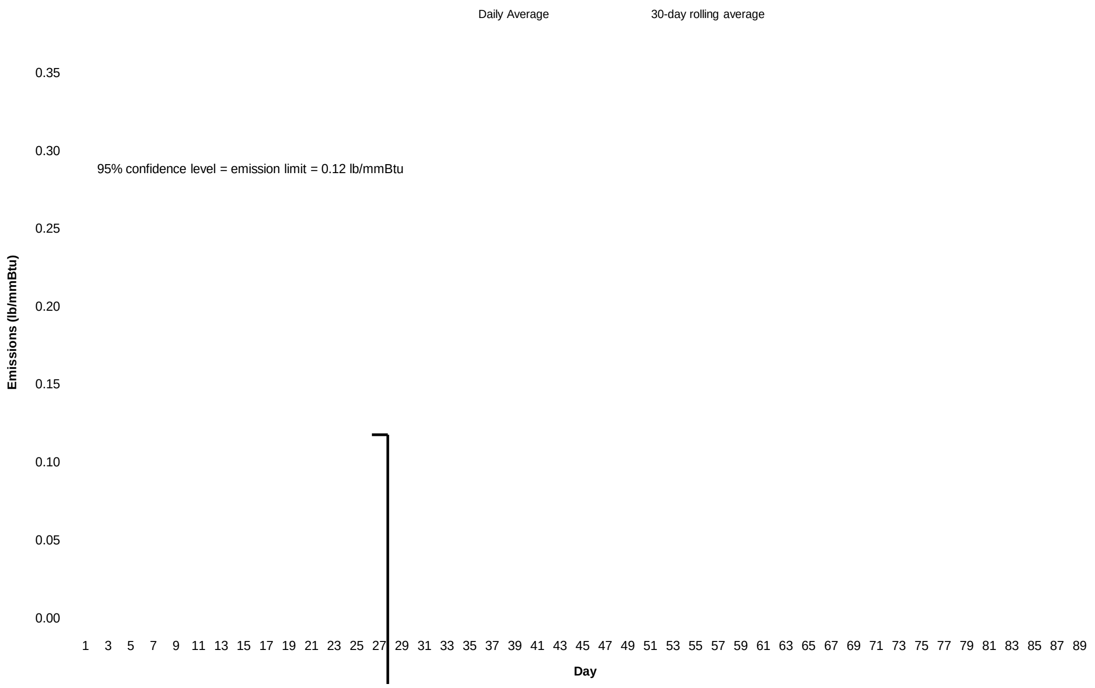

Figure 1: Hypothetical emission trends and averages.

Selecting the appropriate averaging time is based on the variability of the source being regulated and the expected performance of the pollution control equipment that will be used to meet the limit. The BART guidelines recommend a 30-day rolling average for coal fired electric generating units, which is consistent with the New Source Performance Standards promulgated by EPA in 40 CFR Part 60, Subpart Da for electric generating units that commenced construction after September 18, 1978. The limits in subpart Da are based on similar controls being considered in this BART determination.

For new sources, establishing a limit can be a difficult process because of limited information. However, for retrofits at existing sources, we have the benefit of reviewing emissions data from actual operations to determine appropriate limits. The federal Acid Rain program requires continuous monitoring of SO_2 and NO_x emissions from coal fired electric generating units and the data must be submitted to the Clean Air Markets Division (CAMD). The data is accessible from the internet at http://www.epa.gov/airmarkets/index.html. The Department has reviewed this data to determine the control effectiveness of control technologies in operation throughout the western United States. With the exception of the Centralia plant in Washington, the Department selected units similar to the unit at the Boardman Plant (e.g., dry bottom wall fired units). The units at the Centralia Plant are tangentially fired, but are included to evaluate the SO_2 emissions with a Wet FGD system, which is less dependent on the boiler design. The following is a summary of the **best performing units**[12] for each control technology.

Table 12: Western state best performing control systems

Pollutant	Control	State	Facility	ORISPL	Unit	Nominal Unit size (MW)	Months of Data	Emissions Average[2] (lb/mmBtu)	95% confidence (lb/mmBtu)
NOx	LNB[1]	CO	Craig	6021	C-1	459	36	0.273	0.294
NOx	LNB	CO	Craig	6021	C-2	463	33	0.276	0.303
NOx	LNB	KS	Holcomb	108	SGU1	365	36	0.317	0.362
NOx	LNB	MI	Endicott	4259	1	56	36	0.226	0.317
NOx	LNB	MI	JB Sims	1825	3	69	32	0.250	0.313
NOx	LNB	NE	GGS	6077	1	660	23	0.217	0.266
NOx	LNB	TX	HW Pirkey	7902	1	691	36	0.180	0.208
	LNB average							**0.248**	**0.295**
NOx	LNB/SCR	AZ	Springerville	8223	TS3	452	19	0.078	0.086
NOx	LNB/SCR	MO	Hawthorne	2079	5A	564	36	0.076	0.101
	LNB/SCR average							**0.077**	**0.094**
SO2	SDFGD	AZ	Springerville	8223	TS3	452	19	0.097	0.121
SO2	SDFGD	CO	Craig	6021	C-3	443	47	0.113	0.145
SO2	SDFGD	KS	Holcomb	108	SGU1	365	36	0.206	0.199
SO2	SDFGD	MO	Hawthorne	2079	5A	564	34	0.097	0.129
	SDFGD average							**0.128**	**0.149**
SO2	WFGD	CO	Craig	6021	C-1	459	35	0.046	0.070

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[12] The best performing units are presumed to include units with the lowest emission limits (e.g., Best Available Control Technology standards) or may be operated at reduced emission levels for other reasons, such as generating credits for the Acid Rain program.

Pollutant	Control	State	Facility	ORISPL	Unit	Nominal Unit size (MW)	Months of Data	Emissions Average[2] (lb/mmBtu)	95% confidence (lb/mmBtu)
SO2	WFGD	CO	Craig	6021	C-2	463	33	0.053	0.093
SO2	WFGD	NM	Four Corners	2442	1	188	34	0.124	0.180
SO2	WFGD	NM	Four Corners	2442	2	187	34	0.133	0.177
SO2	WFGD	NM	Four Corners	2442	3	243	34	0.160	0.232
SO2	WFGD	UT	Bonanza	7790	1-Jan	481	48	0.055	0.093
SO2	WFGD	UT	Hunter	6165	3	971	36	0.074	0.121
SO2	WFGD	UT	Intermountain	6481	1SGA	948	36	0.051	0.074
SO2	WFGD	UT	Intermountain	6481	2SGA	944	36	0.050	0.074
SO2	WFGD	WA	Centralia	3845	BW21	730	18	0.042	0.070
SO2	WFGD	WA	Centralia	3845	BW22	781	21	0.047	0.082
	WFGD average							**0.076**	**0.115**
	WFGD average without Four Corners							**0.055**	**0.088**

[1] LNB = New low NO_x burners with modified overfire air system.

[2] Based on CAMD monthly averages (not rolling 30-day averages)

Based on the data reviewed, the Department agrees with the control effectiveness presented by PGE with the following exceptions:

- PGE proposed a control effectiveness of 0.28 lb/mmBtu heat input for New LNB with Modified OFA air system. Unit 1 at the Gerald Gentleman Station (GGS #1) in Nebraska is nearly identical to the unit at the Boardman Plant. A new LNB with Modified OFA system was installed on GGS#1 in 2004. As shown above, the average emission rate for the 23 months through March 2008 was 0.22 lb/mm Btu heat input and the 95% confidence level is 0.27 lb/mmBtu. Based on this information, the Department believes that the control technology can achieve 0.23 lb/mmBtu as an annual average. This is equivalent to the BART presumptive limit, except with a different averaging period.

- PGE proposed a control effectiveness of 0.09 lb/mmBtu heat input for Wet FGD. Based on a review of the data for the Centralia unit BW21 and Craig unit C-1, the Department believes that Wet FGD can achieve 0.07 lb/mmBtu as a 30-day rolling average.

The Department could not find any dry bottom wall fired units with SNCR in the Western United States, but there are several in the Eastern United States. Of the 23 units reviewed, most of them have average monthly emissions greater than 0.23 lb/mmBtu heat input, but there are four units that have emissions in the range of 0.17 to 0.26 lb/mmBtu heat input during the ozone season. Three of these units are much smaller than the Boardman Plant, but Unit 2 at the Hudson Generating Station is just a little smaller than the Boardman Plant. The emissions from this unit ranged from 0.18 to 0.23 lb/mmBtu heat input, indicating that SNCR coupled with low NO_x burners and overfire air could possibly meet the presumptive BART limit. As with all of the NO_x controls, it appears that the control effectiveness of SNCR is very specific to the unit design, size, and type of coal.

The Department received several comments that the control effectiveness PGE proposed for SCR is too high based on actual performance in the eastern United States. The Department's consultant, ERG, also pointed out that SCR can achieve 70% to 90% control efficiency and NO_x emission levels as low as 0.05 lb/mmBtu heat input. As shown above, the best performing emission units in the western US could not achieve these levels even without considering the emissions variability. There are considerably more applications of SCR in the eastern US in response to the NO_x SIP call and Clean Air Interstate Rule (CAIR). Typically, SCR have been installed to reduce NO_x emissions during the ozone season, which means that many are not operated all year long, providing substantial opportunity for off-season maintenance and catalyst cleaning. Again, the search was limited to dry bottom wall fired units because the effectiveness of NO_x emissions control technology is somewhat dependent on boiler design. Provided below is a summary of the best performing units identified in the search.

Table 13: Eastern state best performing SCR systems

Pollutant	Control	State	Facility	ORISPL	Unit	Nominal Unit size (MW)	Months of Data	Emissions Average (lb/mmBtu)	95% confidence (lb/mmBtu)
NO_x	LNB/SCR	NC	Asheville	2706	1	175	8[1]	0.064	0.096
NO_x	LNB/SCR	NC	Asheville	2706	2	160	15[1]	0.057	0.084
NO_x	SCR	AL	Colbert	47	5	450	7[2]	0.041	0.058
NO_x	SCR	KY	Ghent	1356	3	500	5[2]	0.088	0.190
NO_x	SCR	KY	Ghent	1356	4	500	5[2]	0.040	0.128
NO_x	SCR	KY	Mill Creek	1364	3	420	5[2]	0.049	0.103
NO_x	SCR	KY	Mill Creek	1364	4	520	5[2]	0.037	0.072

[1] Based on monthly averages
[2] Based on daily averages

The Department's goal is to establish both stringent and realistic performance limits for the Boardman facility. Based on the assessment of performance levels at comparable facilities around the country, the Department proposes NO_x limits of 0.28 lbs/MMBtu (30-day avg) and 0.23 lbs/MMBtu (annual avg) for new low NO_x burners with modified overfire system and 0.07 lbs/MMBtu (30 day avg) for selective catalytic reduction.

The control effectiveness limits discussed above are all in terms of pounds per million Btu heat input. Another way to express the control effectiveness would be on a percent reduction basis. However, the Department does not believe that the control effectiveness should be based on a percent reduction due to the fact that the Boardman plant burns low-sulfur coal and utilizes low NO_x burners. The current SO_2 emission rate is about 0.6 lb/mmBtu heat input. In order to meet a 90% emission reduction the emissions at the outlet of the control device would have to be 0.06 lb/mmBtu heat input, which is not achievable based on the analysis of the best performing units with similar control devices. The same can be said for NO_x because the current emissions are about 0.43 lb/mmBtu heat input and a 90% reduction would require an emission rate at the outlet of the control device(s) of 0.043 lb/mmBtu heat input. The available emissions data from similar sources indicates that an emission rate of 0.043 lb/mmBtu heat input could not be achieved in practice.

Step 4: Evaluate impacts and document the results

The BART guidelines identify 4 parts to an impact analysis:

1. Costs of compliance
2. Energy impacts
3. Non-air quality environmental impacts
4. Remaining useful life

PGE did not consider the remaining useful life of the plant as a factor in their BART analysis, so the impact is considered negligible. The useful life has a bearing on the cost analysis. Any time less than 20 years would increase the amortized cost and the cost effectiveness.

Cost Estimates

PGE calculated the capital investment and annual operating cost for each technically feasible control option 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

The Department contracted ERG to review the costs provided by PGE with specific attention to the NO_x control technologies. ERG employed several methods to estimate likely costs, including using industry-standard cost estimation models, literature searches of costs incurred in similar projects across the county, and discussions with PGE's contractor Black & Veatch to explore "real-world" costs for these types of projects. ERG's costs estimates are lower than cost estimates initially provided by PGE. **Table 14** below shows the costs for Phase 1 NO_x control and the total (Phase 2) NO_x control package of New Low NO_x Burning with Over-fired air + Selective Catalytic Reduction (SCR) based on both PGE and ERG estimates.

Table 14: Cost estimates (Capital Costs and Dollars per Kilowatt)

NO_x **Control**	**PGE Estimate Capital Cost $**	**ERG Estimate Capital Cost $**	**PGE Estimate $/kW**	**ERG Estimate $/kW**	**Difference**
BART (Phase 1) Low NO_x Burner Over-fired-air	$32,651,000	$22,212,000	53	36	~47%
Complete NO_x Package- BART (LNB with OFA) + Phase 2 NO_x control (SCR)	$223,510,000	176,462,000	362	286	~27%
Total DEQ Rule Package for NO_x And SO2	470,803,000	423,800,000	715	643	~11%

The major difference between the two cost estimates is that PGE included an additional $40 million dollars for boiler modifications needed to reduce the temperature of flue gases to the range required by the SCR. Retrofit projects usually involve some modifications to the boiler, but not to the extent required for the Boardman retrofit project. ERG provided a range of costs and believes that the cost for the Boardman retrofit would be in the upper range of costs due to the complexity of the retrofit. The Department has since obtained additional information from PGE documenting the extent of the expected boiler modifications. Instead of just modifying the lower economizer, it is now expected that the lower economizer will have to be completely replaced with a larger one. Based on this information, the Department believes that the additional $40 million dollars is justified.

DEQ believes it has captured the likely range of costs associated with NO_x controls at the Boardman facility. ERG's estimates reflect reasonable values reflective of other NOx control situations around the country. DEQ's estimates rely on ERG's work, and also factor in costs more specific to the Boardman boiler modification. Currently, DEQ and PGE's best costs estimates for the entire SO2/NOx rule package are within about 11 percent of each other.

Given all the complexities of estimating costs for projects of this scale and the fact that these are high level estimates without detailed engineering, DEQ thinks the PGE and ERG cost estimates for the entire NO_x package are reasonably consistent. Given ERG's research into similar projects across the country, and ERG's in-depth conversations with PGE's consultant on expected "real-world" costs, and the additional information supporting the boiler modification costs, DEQ thinks PGE's cost estimates are appropriate for the fiscal impact analysis.

Because DEQ and PGE's cost estimate are reasonably similar (within about 11%), DEQ has presented PGE's total estimated capital costs in the following sections of this report. DEQ believes it is better for the sake of clarity to present one number that reflects a reasonable estimate of expected cost.

Table 15: Summary of costs for BART control options

Technology	Emission rate[1] (lb/mmBtu)	Emission reduction (tons/yr)	Capital Cost (million $)	Annual cost (million $/yr)	Cost effectiveness ($/ton/yr)	Incremental cost effectiveness ($/ton/yr)
NO_x:						
LNB/MOFA	0.23	4,756	$32.7	$~~2~~3.7	$782	---
LNB/MOFA/SNCR	0.23	4,756	$50.1	$~~5.3~~7.1	$1,496	---
SCR	0.07	8,647	$190.9	$~~19.6~~23.1	$2,666	$4,097
LNB/MOFA/SCR	0.07	8,647	$223.5	$~~22.3~~26.8	$3,096	$5,052
SO_2:						
SDFGD	0.12	11,988	$247.3	$36.6	$3,055	---
WFGD	0.07	13,202	$382.4	$51.9	$3,933	$12,596

[1] 30-day rolling average, except LNB/MOFA is a 12-month rolling average.

The costs presented above are real world estimates in 2007 dollars. The Department received comments suggesting that the costs be evaluated using only EPA's Cost Manual or CUECost for national consistency. As pointed out in ERG's memo, these tools by themselves do not provide a real world estimate of costs. The Department believes it is important to provide the public and interested parties with as accurate information about the costs as possible.

The emission reductions identified in Table 15 were determined based on the control effectiveness for each control option and the highest rolling 12 month heat input data during the 2003 to 2005 period corresponding with the highest emission rate for each pollutant. For NO_x, the maximum heat input was 48,630,688 million Btu for the 12-month period ending September 2003. For SO_2, the maximum heat input was 48,571,330 million Btu for the 12-month period ending August 2005. For PM, the maximum heat input was 49,093,487 million Btu for the 12-month period ending March 2004. The baseline and projected emissions are summarized as follows:

Table 16: Control Effectiveness and Annual Emissions:

Pollutant	Control Technology	Control Effectiveness (lb/mmBtu)	Annual Emissions (tons)
NO_x	Baseline	0.43	10,349
	LNB/MOFA	0.23	5,593
	LNB/MOFA/SNCR	0.23	5,593
	SCR	0.07	1,702
	LNB/MOFA/SCR	0.07	1,702
SO_2	Baseline	0.61	14,902
	SDFGD	0.12	3,643
	WFGD	0.07	2,429
PM	Baseline	0.017	417
	PJFF	0.012	295

Energy and Non-air impacts:

Included in the annual operation and maintenance portion of the annualized costs presented above are the energy and non-air costs. Provided below is a summary of these costs for each control option. The direct energy impacts for each control technology are based on the auxiliary power consumption of the control technology and the additional draft system power consumption necessary to overcome the control technology resistance in the flue gas flow path. Indirect energy impacts, such as the energy to produce raw materials used for the control technology were not included. The non-air environmental costs are primarily associated with the handling of the byproduct (waste) produced by each control technology. In addition, the cost of treating and handling the water necessary to run the systems is provided for information purposes.

Table 17: Energy and non-air quality environmental costs

Control Technology	Auxiliary and ID Fan Power ($/year)	Byproduct Disposal ($/year)	Water costs ($/year)
New LNB with MOFA	$0	$0	$0
New LNB with MOFA & SNCR	$26,000	$0	$179,000
New LNB with MOFA and SCR	$944,000	$1,000	$0
SDFGD	$1,522,000	$742,000	$300,000
WFGD	$6,979,000	$806,000	$532,000

ERG Notes:

- PGE estimates that an SCR unit will require about 36 times more power than an SNCR system. This may be a low estimate because CUECost generates a differential of about 100 times.
- The cost of managing the spent catalyst for the SCR system may be overstated due to evolving management practices in which the catalyst can be regenerated and re-used for several cycles before disposal.

In addition to the energy and non-air costs listed above, the Department has the following concerns for some of the control technology options:

Table 18: Non-air quality environmental concerns

Control Technology	Non-air environmental concerns
NLNB/MOFA	Increased carbon monoxide
	Boiler tube slagging
SNCR	Ammonia option has safety issues
	Urea option produces CO_2
	Ammonia slip
	Ammonia bisulfate fouling of the preheater
SCR	Ammonia handling safety
	SO_2 to SO_3 conversion – air preheater corrosion
	Ammonium bisulfate formation (air preheater fouling)
	Soot blowing to manage ash deposition in the catalyst
	Reliability of catalyst in high temperature application
	Ammonia slip
SDFGD	Fugitive emissions from raw material and byproduct handling
WFGD	Fugitive emission from raw material and byproduct handling
	Persistent water plume from stack
	Material corrosion
	Dewatering
	Addition of PJFF for mercury control

While many of the concerns can be adequately addressed with a well designed system, they could lead to unforeseen environmental problems. For instance, if boiler tube slagging leads to more tube leaks, then there will be more shutdowns and startups to fix the leaks which could lead to more excess emissions for at least particulate matter.

The Department recommends the use of combustion controls in place of selective non-catalytic reduction to avoid having any ammonia emissions in Phase I, if possible and still meet the presumptive BART limits. Although SNCR helps to reduce NO_x emissions, the excess ammonia that does not react with the NO_x will add to the overall background level of ammonia in the region and may have some small affect on haze formation and nitrogen deposition. For this reason, the Department would like to avoid the use of ammonia if it does not result in a significant decrease in NO_x emissions.

Greenhouse Gases:

Low NO_x burners will produce a lot more carbon monoxide (CO), which will not go out of the stack as CO_2. The increase in CO will be somewhere between 500 and 5,000 tons. In addition, it is not known what effect low NO_x burners will have on the formation of N_2O, which is a persistent greenhouse gas. Staged combustion could result in the formation of less of N_2O initially, but may also prevent the destruction of N_2O later in the combustion process.

If urea is used for either selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) then a mole of CO_2 will be formed for every two moles of NO_x reduced. CO_2 and NO_x have about the same molecular weight (44 and 46 lb/lb mole, respectively), so a ton of CO_2 will be produced for every 2 tons of NO_x eliminated. PGE could be required to use anhydrous ammonia instead of urea and then there wouldn't be any additional CO_2 emissions. This will have to be considered with the rule package.[13]

The SO_2 controls should use lime (CaO) so there shouldn't be any CO_2 emissions. However, limestone ($CaCO_3$) could be used in place of lime and then there would be a mole of CO_2 produced for every mole of SO_2 captured. The molecular weight of SO_2 is 64 lb/lb mole, so about 2/3 of a ton of CO_2 would be produced for every ton of SO_2 captured. It is anticipated that the control systems will capture about 12,000 tons of SO_2, so the CO_2 emissions could be as much as 8,000 tons per year. PGE could be required to use lime to ensure that there wouldn't be any CO_2 increases. This will have to be considered with the rule package but even if limestone is prohibited at the Boardman plant, the conversion from limestone to lime would have to occur at another location and CO_2 would be released in this process.

Mercury controls should not have any direct affect on greenhouse gases.

All of the controls with the exception of low NO_x burners, will require more energy to overcome the resistance they produce in the exhaust system. Any electricity used internally will not be available to the grid. A net reduction in electricity production would have to be offset by electricity from other sources. If the other sources are combustion sources, then there will be an indirect increase in greenhouse gases as a result of the control equipment. If the electricity offsets come from wind or solar, then the associated greenhouse gases would be substantially less.

Other concerns include the greenhouse gases released as a result of manufacturing the reagents. Some of these processes, such as lime kilns for producing CaO, are very energy intensive. There will also be greenhouse gases produced as a result of handling the reagents and products. Trucks and trains will be required to move this material around. And, of course, there are the greenhouse gases associated with all of the manufacturing and transporting of the materials needed for installing the controls.

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[13] Although there will be additional CO_2 emissions from using Urea at the Boardman Plant, urea is produced by combined CO_2 with ammonia, so the net impact to the environment should be zero. The CO_2 consumed in producing urea will offset the CO_2 released from the Boardman stack.

An accurate accounting of greenhouse gas emissions associated with this proposal is beyond the scope of this analysis. However, the Department can say that adding NO_x and SO_2 controls for visibility improvement will not be greenhouse gas neutral.

Cost-Benefit Analysis:

There are several different metrics that can be considered when evaluating the cost-benefit relationships of different emission control technologies. A commonly used metric is dollars per tone of pollution reduced ($/ton). Another common metric is the incremental cost difference between one control option and another. The Department believes that the metrics of dollars per ton and incremental cost differences best express the relative value of various control options and are most comparable with other decision making processes used by state and federal air quality agencies to evaluate emission controls for major industry. As discussed in the next section, the Department has also evaluated the amount of visibility improvement gained in relation to cost in dollars per deciview improvement ($/dv). Dollars per deciview can be informative and important to consider, however this type of metric is not commonly used to assess the cost effectiveness of industrial controls and has more inherent uncertainty in expressing the full visibility and environmental benefit of any given option. This uncertainty potentially makes this metric less helpful than $/ton or incremental costs.

At first glance, it would appear that the cost effectiveness ($/ton/yr) for all of the control technologies is reasonable were this a new source. However, for a retrofit analysis it is important to look at not only the cost for each control, but also the relative costs of the available control options and the incremental cost (e.g., how much more is the cost for the additional emission reductions or environmental benefit).

For NO_x, there is a significant step increase in the capital cost when going from NLNB or SNCR to SCR. SCR is at least $140 million dollars more than LNB or SNCR and 3 to ~~8~~ 6 times as much. In addition, the incremental cost in $/ton removed for SCR is at least 5 times the cost effectiveness of LNB or SNCR ($782/ton for LNB compared to about $4,100/ton for SCR). For SO_2, the capital cost of WFGD is $135 million dollars more than for SDFGD, and the incremental cost is 4 times higher than the cost effectiveness for SDFGD ($3,100/ton for SDFG vs. $12,596/ton for WFGD).[14]

~~A complete summary of the cost analysis is provided in Attachment B.~~

Step 5: Evaluate visibility impacts

The Department, with the assistance of the Idaho Department of Environmental Quality (IDEQ) and Washington Department of Ecology (WDOE) and consultation with the U.S. Fish and Wildlife Service, National Park Service, U.S. Forest Service, and U.S. EPA Region 10, developed a modeling protocol for assessing the visibility impacts of source's emissions on federal Class I Areas. The protocol specified the modeling programs (CALMET, CALPUFF, and CALPOST), meteorology (MM5), time period (years 2003 through 2005), range of influence (300 kilometers) and source emissions levels (highest 24-hour average emissions) to be used for

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[14] A complete summary of the cost analysis can be found in DEQ's PGE Boardman Cost Spreadsheet.

assessing visibility impacts on Federal Class I areas. In addition, the protocol specified that any BART-eligible source with a visibility impact greater than 0.5 deciview (dv) based on the 22nd highest day for the three year period or 8th highest day for any one year contributes to visibility impairment and is subject to BART.

The model produces results in terms of *deciviews*. A deciview (dv) is a measure of visibility impairment. A 0.5 deciview change equals about a 5% change in visible range (e.g., how far one can see) and is barely perceptible by about 50% of observers. A 1.0 deciview change is perceptible by almost all observers. Deciviews and percent change in visible range are approximately linear in the lower end of the scale. A delta deciview is the change in deciviews relative to natural visibility background. The natural visibility background is defined as the 20% best days determined in accordance with EPA's "Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule".

For baseline modeling (e.g., exemption modeling), PGE reviewed the emissions data during the 2003 through 2005 time period to determine the highest 24-hour daily average emissions during periods other than startup, shutdown, and malfunction. The highest emissions for each pollutant were used in the model. For the demonstration modeling, the emission rates were calculated using the control effectiveness of the control technique and the heat input corresponding to the highest emission rate determined during the 2003 through 2005 time period. In addition, the specific stack parameters to be used in the model were determined based on actual measurements or predictions based on the control device design.

PGE conducted visibility modeling using the approved modeling protocol for the following control options and combinations of control options:

Table 19: PGE modeling emission rates

Pollutant	Control Technology	Emission rates (lb/mmBtu Heat input)		
		NO_x	SO_2	PM
Baseline (NO_x, SO_2, PM)	ESP, low sulfur coal	0.43	0.61	0.015
NO_x	NLNB/MOFA and SNCR	0.23	0.61	0.015
NO_x	NLNB/MOFA and SCR	0.07	0.61	0.015
SO_2	SDFGD (PJFF)	0.43	0.15	0.012
SO_2	WFGD (PJFF)	0.43	0.10	0.012
Combined controls (NO_x, SO_2, PM)	NLNB/MOFA/SNCR/SDFGD	0.23	0.15	0.012

Note: PGE revised the emission rates for SDFGD and WFGD to 0.12 and 0.09 lb/mmBtu heat input, respectively, but did not re-run the model.

The Department also conducted modeling using the approved modeling protocol for the control options listed above, but also ran the model for additional control options and emission rates. For those control options that were both modeled by PGE and the Department, the results were nearly identical. The results of the Department's modeling are used in the discussion below.

Table 20: DEQ modeling emission rates:

Pollutant	Control Technology	Emission rates (lb/mmBtu Heat input)		
		NO_x	SO_2	PM
Baseline (NO_x, SO_2, PM)	ESP, low sulfur coal	0.43	0.61	0.015
NO_x	NLNB/MOFA	0.28	0.61	0.015
NO_x	NLNB/MOFA and SNCR	0.23	0.61	0.015
NO_x	NLNB/MOFA and SCR	0.07	0.61	0.015
SO_2	SDFG (PJFF)	0.43	0.12	0.012
SO_2	WFGD (PJFF)	0.43	0.07	0.012
Combined (NO_x, SO_2, PM)	NLNB/MOFA/SDFGD (PJFF)	0.28	0.12	0.012
Combined (NO_x, SO_2, PM)	NLNB/MOFA/SNCR/SDFGD (PJFF)	0.23	0.12	0.012
Combined (NO_x, SO_2, PM)	NLNB/MOFA/SCR/SDFGD (PJFF)	0.07	0.12	0.012
Combined (NO_x, SO_2, PM)	NLNB/MOFA/SCR/WFGD (PJFF)	0.07	0.07	0.012

~~The complete results of the modeling are provided in Attachment C.~~ A summary of the results is provided in the following 2 tables. [15]

Table 21: Visibility Modeling Results: Summary of key indicators

Parameter	Baseline 2003-05	NO_x Controls			SO_2 Controls	
		NLNB/ MOFA	SNCR[1]	SCR[1]	SDFGD	WFGD
Mt. Hood[2] visibility impacts (Deciview (dv) 98th percentile)[3]	4.6	4.02	3.40	2.76	3.56	3.80
Days/year >1.0 dv (most frequently impacted Class I area)[4]	63	55	50	42	50	50
Number Class I Areas >1.0 deciview (98th percentile)[5]	14	12	12	11	11	11
Total visibility impacts (sum of 98th percentile dv for all Class I areas)	31.08	26.46	22.59	18.77	20.49	20.70
Average Class I Area visibility impacts (98th percentile dv)	2.22	1.98	1.61	1.34	1.57	1.48

Notes: DEQ draft proposal for combined controls in bold.

1. SNCR and SCR include NLNB/MOFA.
2. Mt Hood is the closest Class I Area to the power plant and it has the highest impacts.
3. The 98th percentile is the 22nd highest daily value for the three year period of 2003 through 2005.
4. The average number of days per year was determined by dividing the maximum number of days for the 3-year period for the most frequently impacted Class I area by 3. Hells Canyon is the most frequently impacted Class I area in baseline, but Mt. Hood is the most frequently impacted Class I area in all other scenarios. The number of days is based on all data, including the days with impacts greater than the 98th percentile.

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[15] The complete results of the modeling can be found in DEQ's PGE Boardman Modeling Spreadsheet.

5. 14 Class I Wilderness Areas and National Parks within 300 km of the power plant were modeled. Other Class I areas farther from the power plant may be impacted, but the impacts would be less than presented in the table.

Table 22: Visibility Modeling Results (percent improvement)

Parameter	NO_x Controls			SO_2 Controls	
	NLNB/ MOFA	SNCR	SCR	SDFGD	WFGD
Mt. Hood visibility impacts (98th percentile delta dv)	13%	26%	40%	23%	17%
Days/year >1.0 delta dv (most frequently impacted Class I area)	13%	21%	33%	21%	21%
Total visibility impacts (sum of 98th percentile delta dv for all Class I areas)	15%	27%	40%	34%	33%
Average Class I Area visibility impacts (delta deciview)	11%	27%	40%	29%	33%
Average for all parameters	13%	25%	38%	27%	26%

The BART guidelines recommend analyzing visibility improvement for the highest impacted Class I area with the assumption that any improvement in the worse impacted area would result in improvement in the lesser impacted areas. However, since the Boardman Plant significantly impacts 14 Class I Areas within 300 kilometers, the Department tried to include other parameters that would assess the significance of the improvements for all Class I areas impacted. Therefore, the Department added the number of Class I areas with impacts greater than 1.0 delta deciview, the total delta deciviews for all Class I areas (98th percentile), and the average delta deciview for all Class I areas (98th percentile). As can be seen in Table 21, any one of the parameters is fairly representative of the other parameters perhaps with the exception of WFGD. Given these results, the Department does not believe that adding additional parameters, such as total deciview days, would result in any other conclusions and would probably just add confusion to the analysis (e.g., more days of impacts than are in a year). Using the results of the visibility modeling, the cost effectiveness of the control technologies is recalculated by relating the costs to deciview improvement (Mt. Hood and all Class I areas) as shown in the following 2 tables.

Table 23: Visibility Improvement Cost Effectiveness for Mt. Hood (98th percentile):

Pollutant	Control Technology	Control Effectiveness (lb/mmBtu)	Visibility Improvement (deciview)	Cost effectiveness (million $/dv)	Incremental Cost Effectiveness (million $/dv)
NO_x	NLNB/MOFA	0.28	0.58	$6.4	---
	NLNB/MOFA &SNCR	0.23	1.20	$5.9	$5.5
	SCR	0.07	1.84	12.5	24.9
	NLNB/MOFA & SCR	0.07	1.84	$14.65	$30.7
SO_2	SDFGD	0.12	1.04	$35.2	---
	WFGD	0.07	0.80	$64.9	[1]

[1] Incremental cost effectiveness cannot be calculated because even though WFGD costs more than SDFGD, WFGD produces less visibility improvement.

Table 24: Visibility Improvement Cost Effectiveness for all Class I Areas (sum of 98th percentile):

Pollutant	Control Technology	Control Effectiveness (lb/mmBtu)	Visibility Improvement (deciview)	Cost effectiveness (million $/dv)	Incremental Cost Effectiveness (million $/dv)
NO_x	NLNB/MOFA	0.28	4.62	$0.80	---
	NLNB/MOFA and SNCR	0.23	8.49	$0.84	$0.88
	SCR	0.07	8.49	1.87	4.17
	NLNB/MOFA and SCR	0.07	12.31	$2.17	$5.15
SO_2	SDFGD	0.12	10.59	$3.46	---
	WFGD	0.07	10.38	$5.00	[1]

[1] Incremental cost effectiveness can't be calculated because even though WFGD costs more than SDFGD, WFGD produces less visibility improvement.

The most obvious conclusion from the above data is that, when evaluated by itself, WFGD for SO_2 control does not provide any additional visibility improvement even though the technology is considerably more expensive than SDFGD. When evaluated with SCR, WFGD has only a slight improvement over SDFGD. For NO_x, as with the cost effectiveness based on emission reductions, there is a considerable step increase (factor of 2) in going from NLNB/MOFA with or without SNCR to SCR controls. In addition, the incremental cost is 5 times as much as the cost effectiveness of NLNB/MOFA with or without SNCR.

SELECTION OF BART

The BART guidelines recommend selecting the best retrofit control on a pollutant by pollutant basis taking into consideration the cost, the energy and non-air environmental impacts, the remaining useful life, and the modeled visibility impacts.

Particulate matter:

The Department considers a pulse jet fabric filter (PJFF) to be BART for the following reasons,

- PM contributes very little (<1%) to visibility impairment so an independent BART analysis for PM would probably result in no additional control.
- The cost of PJFF is included in the recommended sulfur dioxide controls.
- PJFF is compatible with and integral to the recommended sulfur dioxide controls.
- PJFF is compatible with and integral to potential mercury controls.
- PJFF can be installed downstream of the existing ESP, but still utilize the existing stack.
- None of the other control alternatives considered achieves a lower emission rate.

Sulfur dioxide:

The Department considers a semi-dry flue gas desulfurization system to be BART for the following reasons:

- The Department recommends semi-dry flue gas desulfurization (SDFGD) as BART because it provides slightly more visibility improvement than wet flue gas desulfurization and the cost is $135 million dollars less.
- SDFGD is consistent with EPA's BART analysis for coal fired electric generating units greater than 200 MW located at 750 MW plants. The unit at the Boardman plant is 617 MW even though the plant is less than 750 MW.
- EPA expected that a semi-dry flue gas desulfurization system can achieve 90% emissions reductions or 0.15 lb/mmBtu heat input. The Department's proposed control effectiveness of 0.12 lb/mmBtu heat input is more stringent than EPA's BART analysis.
- The control effectiveness proposed by the Department is actually slightly better than demonstrated in practice at similar units.
- A wet flue gas desulfurization system has the following negative drawbacks:

    - More water is required for a wet system and the plant is located in a semi-arid region.
    - The water will have to be treated to avoid water pollution
    - A wet/visible plume will be present almost all of the time
    - The wet exhaust gas is corrosive, requiring more maintenance of the duct work and stack
    - An additional fabric filter will have to be added to be compatible with potential mercury controls
    - The existing stack will have to be replaced with a new corrosion resistant stack.

Nitrogen oxides:

The Department considers new low NO_x burners with modified over fire air system (NLNB/MOFA) to meet the statutory requirements for BART. However, due to the design of the boiler, LNB/MOFA may not quite be able to achieve the presumptive limits established by EPA. Therefore, the Department recommends a contingency plan for installing SNCR if it is demonstrated that NLNB/MOFA cannot meet 0.23 lb/mmBtu as a 12-month rolling average. The Department would assess the need to invoke this contingency one year after new Low NO_x Burners are operational. This is based on the following conclusions:

- Low NO_x burners with modified overfire air system provide a significant improvement in visibility impacts at a very reasonable cost; especially when coupled with semi-dry flue gas desulfurization.
- Low NO_x burners with modified overfire air system prevent the formation of NO_x without adding reagents or catalysts.
- PGE proposed adding selective non-catalytic reduction to the low NO_x burners with modified overfire air system. However, if the presumptive BART limit can be met with

low NO_x burners and modified overfire air system, the Department does not recommend SNCR. Even though SNCR is relatively cost effective and has been installed successfully on some boilers in the eastern United States (typically smaller boilers than the Boardman Plant), this control option is not recommended for the following reasons:
  - SNCR requires ammonia (or urea), which poses storage and handling safety concerns
  - SNCR is an inefficient system that can result in very high ammonia emissions (50 to 100 ppm). Unreacted ammonia could contribute to the visibility impacts in Class I areas.
  - The injection system within the boiler will have maintenance problems due to a build up of slag. Additional water will be required to keep the system free of slag.
- New low NO_x burners with modified overfire air are consistent with EPA's BART analysis for dry bottom wall fired boilers greater than 200 MW located at 750 MW plants. The unit at the Boardman Plant is 617 MW and it is a dry bottom wall fired boiler.
- EPA expected that new low NO_x burners with modified overfire air system could achieve 0.23 lbs/mmBtu heat input on a 30-day rolling average. PGE proposed a control effectiveness of 0.28 lb/mmBtu an a 30-day rolling average, but the Department believes that a limit of 0.23 lb/mmBtu on a 12-month rolling average can be met based on actual emissions data for a similar type unit (Gereald Gentleman Station Unit 1).
- Selective catalytic reduction is not recommended within the 2014 timeframe for the following reasons:
  - The capital cost of selective catalytic reduction is 6 times that of new low NO_x burners with modified overfire air system and there is only a 27% improvement in visibility impacts. (LNB/OFA provides a 13% improvement over baseline; whereas, SCR provides a 40% improvement over baseline. The difference is 27%.)
  - There is considerable uncertainty associated with the design and cost of SCR for the Boardman Plant due to the current temperature of the boiler exhaust gas. The temperature will have to be reduced from approximately 850º to <750ºF by modifying the heat transfer system in the backside of the boiler and prior to the air preheater. It is anticipated that this will involve replacing the lower economizer with a much larger one. This type of boiler redesign is not typically involved in retrofit control projects.
  - Due to the complexity of the retrofit, installation of SCR will require more downtime than the usual time allowed for a routine maintenance outage. This will require coordination and planning to minimize the downtime and obtain replacement power during the outage.
  - It is anticipated that there are still many SCR systems that need to be installed on coal fired electric generating units in the eastern United States as a result of the Ozone Transport Commission NO_x Budget Program, NO_x State Implementation Plan Call, and the Clean Air Interstate Rule. The Department believes that this competition will delay projects that may be required for the regional haze program.
  - Delaying installation to 2017 will allow PGE to investigate innovative control systems that don't utilize ammonia to avoid the following issues:

- SCR will require a large amount of ammonia, which poses storage and handling safety concerns.
- Although not as much as with an SNCR system, there will be some un-reacted ammonia (5 to 10 ppm) emitted to the atmosphere. Un-reacted ammonia could contribute to the visibility impacts in Class I areas.
- SO_2 to SO_3 conversion could cause corrosive problems for the air preheater.
- The formation of ammonium bisulfate could damage the air preheater.
- Spent catalyst will eventually have to be disposed of as a hazardous waste.

BART EMISSION LIMITS:

The Department recommends the following emission limits and averaging times for the control options. The limits are based on the control effectiveness, as previously discussed. The averaging times are based on the BART guidelines with the addition of an annual average for the low NO_x burners and overfire air. The 30-day rolling average is also consistent with the federal New Source Performance Standards established for fossil fuel fired steam electric generating units. The NSPS are based on the same type of controls recommended for BART.

Table 25: BART emission limits

Pollutant (year)	Emission limit (lb/mmBtu heat input)	Averaging time
NO_x (2011)	0.28	30-day rolling
NO_x (2011)	0.23	12-month rolling
NO_x (2014 contingency)	0.23	30-day rolling
SO_2 (2014)	0.12	30-day rolling
PM (2014)	0.012	Source test

PGE will be required to demonstrate compliance with the BART standards, but they are not required to install the specific controls discussed above. An alternative control may be installed provided the emission limits can be met.

Compliance Schedule:

Typically, the Boardman Plant is shut down for maintenance each year during the month of May. It is anticipated that the final installation steps for each of the control options would occur during the annual outage. Therefore, the BART compliance schedule is lined up with the annual outage as follows:

Table 26: BART compliance schedule

Pollutant	Emission limit	Installation and Operation Date	Compliance Demonstration Date
NO_x	0.28	7/1/2011	1/1/2012
	0.23	7/1/2011	7/1/2012
NO_x contingency	0.23	7/1/2014	1/1/2015
SO_2	0.12	7/1/2014	1/1/2015
PM	0.012	7/1/2014	1/1/2015

The Department recommends the schedule provided above for the following reasons:

- The NLNB/MOFA system is readily available so the Department recommends that it be installed as expeditiously as possible to get significant emissions reductions as soon as possible.
- The SNCR contingency is based on the performance of the combustion controls so there will be one year to evaluate the combustion controls to determine whether SNCR is necessary. In the event that SNCR is necessary, the Department recommends a two year schedule to complete the design and installation of the SNCR. This schedule will still meet the 5 year deadline mandated by the regional haze rules.
- The PM controls are integral to the SO_2 controls, so the Department recommends the same schedule for both pollutants. Typically, the SO_2 controls can be installed in 3 to 5 years. However, the Department anticipates that there will be considerable demand for materials and labor as a result of BART requirements in other states, so it is anticipated that it will take most of 5 years to complete installation of the controls at the Boardman Plant.

Compliance Monitoring:

Compliance with the NO_x and SO_2 standards will be determined using the continuous emission monitoring systems (CEMS) required by the federal Acid Rain program and Oregon Title V Operating Permit. Compliance with the PM standard will be determined by routine source testing and parameter monitoring of the fabric filter control device. Particulate emissions will be measured using EPA Method 5 (filterable PM). The Department recommends that testing be conducted annually initially. The testing frequency could be reduced to once every 5 years if 2 consecutive annual tests are less than 75% of the standard (0.009 lb/mmBtu). In addition to the compliance testing, the Department recommends continuous monitoring of the fabric filter operating parameters, including but not necessarily limited to a leak detection monitor and pressure drop monitor. PGE will also be required to monitor visible emissions with the existing continuous opacity monitoring system.

PHASE 2 NO_X CONTROLS:

In addition to the controls identified above for BART, the Department recommends the installation of selective catalytic reduction (SCR) or equivalent control by no later than July 1, 2017. The Department believes that this is necessary for the following reasons:

- Current estimates are that the reasonable progress goals for the regional haze plan will not be met with the current strategies. Nitrates contribute to haze in the Class I areas and the Boardman plant will still be a significant source of nitrogen oxides. The modeling conducted for BART shows that further reductions of nitrogen oxides will reduce the impacts of the Boardman plant below 1.0 deciview for all Class I areas and less than 0.5 deciview for most of the Class I areas. This improvement will help meet the reasonable progress goals.
- As with the Class I areas, further reductions in nitrogen oxides will help improve the air quality in the Columbia River Gorge National Scenic Area and reduce risks to ecosystems and Native American cultural resources. Modeling results show that controls put in place by 2014 will reduce the visibility impacts from 3.7 to 2.8 deciviews and the addition of SCR by 2017 will reduce the impacts from the Boardman Plant to 0.8 deciviews.
- SCR will reduce or eliminate the yellow or brown plume that is currently present during some meteorological conditions. This plume is caused when nitrogen oxide (NO) is converted to nitrogen dioxide (NO_2) in the presence of free oxygen.

Schedule for Phase-2 NOx controls:

The Department recommends an extended compliance schedule for installing controls and demonstrating compliance with an emission limit that is representative of SCR for the following reasons:

- Significant modifications to the boiler will be required to reduce the exhaust temperature to the level required for an SCR system. Currently, the exhaust temperature is above 800ºF entering the air preheater where the SCR system would have to be installed. The back side of the boiler will have to be redesigned to lower the temperature to less than 750ºF without significantly lowering the temperature of the combustion air. It is anticipated that this modification will involve the replacement of the lower economizer with a larger one. For most SCR retrofits, new duct work is built along side the existing duct work while the boiler is operating. The SCR system is installed in the new duct work and then connected to the existing ductwork during a scheduled maintenance outage. For the Boardman Plant, the backside of the boiler passage will have to be modified in addition to installing the SCR system. As a result of these complications, more time is required for project engineering and planning.

- A longer than normal outage will be necessary to complete the boiler modifications. The extended schedule will allow more time to plan the project to ensure that the modifications are completed as quickly as possible and that electricity will be available from other sources during the outage.

- Most of the eastern United States SCR retrofit projects should be completed in a few years. This will result in less competition for labor and materials. There is also a considerable amount of competition for materials and labor due to the escalation of activity in China.

- An extended schedule will also allow PGE to evaluate innovative control technologies that may be superior to SCR in that they don't require ammonia or generate hazardous waste. Foster Wheeler is working on an ammonia-free selective catalytic reduction (AF-SCR) system that uses excess carbon monoxide instead of ammonia to reduce NO_x emissions. AF-SCR, if it works, would be well suited for boilers with new low NO_x burners because they generate more carbon monoxide. AF-SCR is still in the pilot stage of development and other technologies may become available that don't require ammonia.

Emission limits and compliance schedule:

As discussed above, the control effectiveness of SCR is considered to be 0.07 lb/mmBtu heat input based on the best performing units in the United States. Therefore, it is recommended that the emission limit for SCR be 0.07 lb/mmBtu heat input on a 30-day rolling average.

Typically, it takes about 3 to 5 years to design and install an SCR system. The Department believes that it will take twice as long for the Boardman plant due to the complexity of the project and competition with current projects throughout the United States and other countries in the world. The Department recommends that SCR be installed by July 1, 2017, which is approximately 8 years from when the rules will be adopted.