ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

PRELIMINARY
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION
for
Chena Power Plant
Aurora Energy, LLC.

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Table of Contents

1. INTRODUCTION 1
2. BACT EVALUATION 1
3. BACT DETERMINATION FOR NOX 3
 3.1 NOx BACT for Coal-Fired Boilers 3
4. BACT DETERMINATION FOR SO_2 9
 4.1 SO_2 BACT for Coal-Fired Boilers 9
5. BACT DETERMINATION SUMMARY 14

Abbreviations/Acronyms

AAC ....Alaska Administrative Code
AAAQS ....Alaska Ambient Air Quality Standards
Department ....Alaska Department of Environmental Conservation
BACT ....Best Available Control Technology
CFB……………………Circulating Fluidized Bed
CFR. ....Code of Federal Regulations
Cyclones………………Mechanical Separators
DFP……………………Diesel Particulate Filter
DLN..............................Dry Low NOx
DOC…………………...Diesel Oxidation Catalyst
EPA ....Environmental Protection Agency
ESP……………………Electrostatic Precipitator
EU.................................Emission Unit
FITR…………………...Fuel Injection Timing Retard
GCPs…………………..Good Combustion Practices
HAP ....Hazardous Air Pollutant
ITR……………………Ignition Timing Retard
LEA……………………Low Excess Air
LNB……………………Low NOx Burners
MR&Rs ....Monitoring, Recording, and Reporting
NESHAPS ....National Emission Standards for Hazardous Air Pollutants
NSCR…………………Non-Selective Catalytic Reduction
NSPS ....New Source Performance Standards
ORL...............................Owner Requested Limit
PSD................................Prevention of Significant Deterioration
PTE................................Potential to Emit
RICE, ICE ....Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR ....Selective Catalytic Reduction
SIP ....Alaska State Implementation Plan
SNCR…………………Selective Non-Catalytic Reduction
ULSD ....Ultra Low Sulfur Diesel

Units and Measures

gal/hr..............................gallons per hour
g/kWh ....grams per kilowatt hour
g/hp-hr ....grams per horsepower hour
hr/day.............................hours per day
hr/yr ....hours per year
hp...................................horsepower
lb/hr ....pounds per hour
lb/MMBtu......................pounds per million British thermal units
lb/1000 gal.....................pounds per 1,000 gallons
kW ....kilowatts
MMBtu/hr......................million British thermal units per hour
MMscf/hr.......................million standard cubic feet per hour
ppmv..............................parts per million by volume
tpy.................................tons per year

Pollutants

CO ....Carbon Monoxide
HAP ....Hazardous Air Pollutant
NOx ....Oxides of Nitrogen
SO_2 ....Sulfur Dioxide
PM-2.5...........................Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10............................Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

Chena Power Plant is a stationary source owned by Aurora Energy, LLC (Aurora) which consists of four boilers. Emission Units (EUs) 4 through 6, also identified as Chena 1, 2, and 3, are coal-fired overfeed traveling grate stokers with a maximum steam production rating of 50,000 lbs/hr each. Maximum design power production is 5 megawatts (MW) each. EU 4 was installed in 1954, while EUs 5 and 6 were installed in 1952. EU 7, also identified as Chena 5, is a coal-fired, spreader stoker boiler with a maximum steam production rating of 200,000 lbs/hr and maximum power production rating of 20 MW. Chena 5 was installed in 1970. Maximum coal consumption is 284,557 tons of coal per year, based on the capacities of EUs 4 through 7. Coal receiving and storage (handling) facilities are located on the north bank of the Chena River, and consist of a rail car receiving station, enclosed coal crusher (receiving building), open storage piles, conveyors, and elevators. Coal is transported by conveyors over the Chena River to the Chena Power Plant, located just above the south bank. In the late 1980's, the coal handling system was renovated.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017. [1]

This report addresses the significant emissions units (EUs) listed in Operating Permit No. AQ0315TVP03, Revision 1. This report provides the Department's review of the BACT analysis for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The following sections review Chena Power Plant's BACT analysis for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent EUs at Chena Power Plant that emit NOx and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&Rs) necessary to ensure Chena Power Plant applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency).

[1] [1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table **A** present the EUs subject to BACT review.

Table A: Emission Units Subject to BACT Review

EU	Emission Unit Name	Emission Unit Description	Rating/Size	Installation or Construction Date
4	Chena 1 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1954
5	Chena 2 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
6	Chena 3 Coal Fired Boiler	Full Stream Baghouse Exhaust	76 MMBtu/hr	1952
7	Chena 5 Coal Fired Boiler	Full Stream Baghouse Exhaust	269 MMBtu/hr	1970

Five-Step BACT Determinations

The following sections explain the steps used to determine BACT for NOx and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies

The Department identifies all available control technologies for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx and SO_2 emissions from equipment similar to those listed in
Table **A**.

Step 2 Eliminate Technically Infeasible Control Technologies

The Department evaluates the technical feasibility of each control technology based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary

The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each technology to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3 and 4 present the Department's Preliminary BACT Determinations for NOx and SO_2.

Step 5 Select BACT

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed Aurora's BACT analysis and made preliminary BACT determinations for NOx and SO_2 for the Chena Power Plant. These preliminary BACT determinations are based on the information submitted by Aurora in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NOx

The NOx controls proposed in this section are not planned to be implemented. The optional preliminary precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the preliminary precursor demonstration for NOx posted at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

Chena Power Plant has three existing 76 million British Thermal Units (MMBtu)/hr overfeed traveling grate stoker type boilers and one 269 MMBtu/hr spreader-stoker type boiler that burns coal to produce steam for stationary source-wide heating and power. The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Combined Heat and Power Plant.

3.1 NOx BACT for the Industrial Coal-Fired Boilers

Possible NOx emission control technologies for coal fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

for Coal Combustion in Industrial Size Boilers and Furnaces. The search results for coal-fired boilers are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	9	0.05 – 0.08
Selective Non-Catalytic Reduction	18	0.07 – 0.36
Low NOx Burners	18	0.07 – 0.3
Overfire Air	8	0.07 – 0.3
Good Combustion Practices	2	0.1 – 0.6

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, selective non-catalytic reduction, low NOx burners, overfire air, and good combustion practices are the principle NOx control technologies installed on industrial coal-fired boilers. The lowest NOx emission rate in the RBLC is 0.05 lb/MMBtu.

Step 1- Identification of NOx Control Technologies for the Industrial Coal-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from the industrial coal-fired boilers:

(a) Selective Catalytic Reduction (SCR)[3]
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the boiler exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. Challenges associated with using SCR on boilers include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a technically feasible control technology for the industrial coal-fired boilers.

(b) Selective Non-Catalytic Reduction (SNCR)[4]
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600°F and 2,100°F. Expected NOx removal efficiencies are typically

[3] https://www3.epa.gov/ttncatc1/dir1/fscr.pdf
[4] https://www3.epa.gov/ttncatc1/dir1/fsncr.pdf

between 40 to 62 percent, according to the RBLC, or between 30 and 50 percent reduction, according to the EPA fact sheet (EPA-452/F-03-031). The Department considers SNCR a technically feasible control technology for the industrial coal-fired boilers.

(c) Non-Selective Catalytic Reduction (NSCR)
NSCR simultaneously reduces NOx and oxidizes CO and hydrocarbons in the exhaust gas to N_2, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen, methane, and CO) to reduce both NO and NO_2 to N_2 at a temperature between 800°F and 1,200°F, below the expected temperature of the coal-fired boiler flue gas. NSCR requires a low excess O_2 concentration in the exhaust gas stream to be effective because the O_2 must be depleted before the reduction chemistry can proceed. NSCR is only effective with rich-burn gas-fired units that operate at all times with an air/fuel ratio controller at or close to stoichiometric conditions. Coal-fired boilers operate under conditions far more fuel-lean than required to support NSCR. The Department's research did not identify NSCR as a control technology used to control NOx emissions from large coal fired boilers installed at any facility after 2005. The Department does not consider NSCR a technically feasible control technology for the industrial coal-fired boilers.

(d) Low NOx Burners (LNBs)
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Overfire air is the injection of air above the main combustion zone. As indicated by EPA's AP-42, LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. The Department does not consider LNBs a technically feasible control technology for stoker type coal-fired boilers.

(e) Circulating Fluidized Bed (CFB)
In a fluidized bed combustor, fuel is introduced to a bed of either sorbent (limestone) or inert material (usually sand) that is fluidized by an upward flow of air. This upward air flow allows for better mixing of the gas and solids to create a better heat transfer and chemical reactions. Combustion takes place in the bed at a lower temperature than other boiler types which lowers the formation of thermally generated NOx. The Department does not consider CFB a technically feasible control technology to retrofit existing coal-fired boilers. For the purposes of this report, a control technology does not include passive control measures that act to prevent pollutants from forming or the use of combustion or other process design features or characteristics. The Department does not

consider CFB a technically feasible control technology to retrofit the existing coal-fired boilers.

(f) Low Excess Air (LEA)
Boiler operation with low excess air is considered an integral part of good combustion practices because this process can maximize the boiler efficiency while controlling the formation of NOx. Boilers operated with five to seven percent excess air typically have peak NOx formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NOx is reduced. At higher levels of excess air, an increase in the formation of CO occurs. CO can increase exponentially at very high levels of excess air and the combustion efficiency is greatly reduced. As a result, the preference is to reduce excess air such that both NOx and CO generation is minimized and the boiler efficiency is optimized. Only one RLBC entry identified low excess air technology as a NOx control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described in the previous LNB discussion. The Department considers LEA a technically feasible control technology for the industrial coal-fired boilers.

(g) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone; and
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control option for the coal-fired boilers.

(h) Fuel Switching
This evaluation considers retrofit of existing coal-fired boilers. It is assumed that use of another type of coal would not reduce NOx emissions. Therefore, the Department does not consider the use of an alternate fuel to be a technically feasible control technology for the industrial coal-fired boilers.

(i) Steam / Water Injection
Steam/water injection into the combustion zone reduces the firing temperature in the combustion chamber and has been traditionally associated with reducing NOx emissions from gas combustion turbines but not coal-fired boilers. In addition, steam/water has several disadvantages, including increases in carbon monoxide and un-burned hydrocarbon emissions and increased fuel consumption. Further, the Department found that steam or water injection is not listed in the EPA RBLC for use in any coal-fired boilers and it would be less efficient at controlling NOx emissions than SCR. Therefore,

the Department does not consider steam or water injection to be a technically feasible control option for the existing coal-fired boilers.

(j) Reburn
Reburn is a combustion hardware modification in which the NOx produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NOx created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NOx reduction of 50 to 60 percent from uncontrolled levels may be achieved. Reburn combustion control would require significant changes to the design of the existing boilers. Therefore, the Department does not consider reburn to be a technically feasible control technology to retrofit the existing industrial coal-fired boilers.

Step 2 - Elimination of Technically Infeasible NOx Control Options for Coal-Fired Boilers
As explained in Step 1 of Section 3.1, the Department does not consider non-selective catalytic reduction, low NOx burners, circulating fluidized beds, fuel switching, steam/water injection, or reburn as technically feasible technologies to control NO_x emissions from existing industrial coal-fired boilers.

Step 3 - Ranking of Remaining NOx Control Technologies for Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the coal-fired boilers:

(a)	Selective Catalytic Reduction	(70% - 90% Control)
(b)	Selective Non-Catalytic Reduction	(30% - 50% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(f)	Low Excess Air	(10% - 20% Control)

Step 4 - Evaluate the Most Effective Controls

Aurora BACT Proposal

Aurora provided an economic analysis for the installation of SCR on all four boilers combined (EUs 4 through 7). Aurora also provided an economic analysis for the installation of SNCR on the three 76 MMBtu/hr boilers (EUs 4 through 6), the 269 MMBtu/hr boiler (EU 7), and all four boilers combined (EUs 4 through 7). A summary of the analyses is shown in Table 3-2.

Table 3-2. Aurora Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (EUs 4 – 7)	784	564	$73,069,750	$15,994,554	$28,347
SNCR (EUs 7)	342	103	$2,792,684	$784,066	$7,649
SNCR (EUs 4 – 6)	439	132	$4,906,782	$1,589,578	$12,059
SNCR (EUs 4 – 7)	781	234	$7,699,466	$2,373,645	$10,130

Aurora's economic analysis indicates the level of NOx reduction does not justify the use of SCR or SNCR for the coal-fired boilers based on the excessive cost per ton of NOx removed per year.

Aurora proposes the following as BACT for NOx emissions from the coal-fired boilers:

(a) NOx emissions from the operation of the coal-fired boilers will be controlled with existing combustion controls;

(b) NOx emissions from the coal-fired boilers will not exceed 0.36 lb/MMBtu; and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

Department Evaluation of BACT for NOx Emissions from the Industrial Coal-Fired Boilers

The Department revised the cost analyses provided by Aurora for the installation of SCR and SNCR using the cost estimating procedures identified in EPA's May 2016 Air Pollution Control Cost Estimation Spreadsheets for Selective Catalytic Reduction[5] and Selective Non-Catalytic Reduction,[6] using the unrestricted potential to emit for the four coal-fired boilers, a baseline emission rate of 0.5 lb NOx/MMBtu,[7] a retrofit factor of 1.0 for projects of average retrofit difficulty, a NOx removal efficiency of 80% and 40% for SCR and SNCR respectively, and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-3. Department Economic Analysis for Technically Feasible NOx Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SCR	794	635	$17,331,770	$2,787,995	$3,240
SNCR	794	318	$3,930,809	$957,728	$2,226
Capital Recovery Factor = 0.094 (7% interest rate for a 20 year equipment life)					

The Department's preliminary economic analysis indicates the level of NOx reduction justifies the use of SCR or SNCR as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

5 https://www3.epa.gov/ttn/ecas/docs/scr_cost_manual_spreadsheet_2016_vf.xlsm
6 https://www3.epa.gov/ttn/ecas/docs/sncr_cost_manual_spreadsheet_2016_vf.xlsm
7 New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997.

Step 5 - Preliminary Selection of NOx BACT for the Industrial Coal-Fired Boilers

The Department's preliminary finding is that selective catalytic reduction and selective non-catalytic reduction are both economically and technically feasible control technologies for NOx. Since selective catalytic reduction has a higher control efficiency, it is selected as BACT to control NOx emissions from the industrial coal-fired boilers.

The Department's preliminary finding is that BACT for NOx emissions from the coal-fired boilers is as follows:

(a) NOx emissions from EUs 4 through 7 shall be controlled by operating and maintaining SCR at all times the units are in operation;

(b) NOx emissions from DU EUs 4 through 7 shall not exceed 0.10 lb/MMBtu averaged over a 3-hour period; and

(c) Initial compliance with the proposed NOx emission rate will be demonstrated by conducting a performance test to obtain an emission rate.

Table 3-4 lists the proposed NOx BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 3-4. Comparison of NOx BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1,380 MMBtu/hr	0.10 lb/MMBtu[8]	Selective Catalytic Reduction
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.04 lb/MMBtu[9]	Selective Catalytic Reduction
Chena	4 Coal-Fired Boilers	497 MMBtu/hr	0.10 lb/MMBtu[7]	Selective Catalytic Reduction

4. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

4.1 SO_2 BACT for the Industrial Coal-Fired Boilers

Possible SO_2 emission control technologies for coal-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 11.110, Coal Combustion in Industrial Size Boilers and Furnaces. The search results for the coal-fired boilers are summarized in Table 4-1.

[8] Calculated using an 80 percent NOx control efficiency for selective catalytic reduction, assuming a baseline of 0.5 lb NOx / MMBtu (New Source Performance Standards, Subpart Da – Technical Support for Proposed Revisions to NOx Standard, U.S. EPA, Office of Air Quality Planning and Standards, EPA-453/R-94-012, June 1997).

[9] Calculated using an 80 percent NOx control efficiency for selective catalytic reduction, assuming a baseline of 0.20 lb NOx / MMBtu (Babcock & Wilcox).

Table 4-1. RBLC Summary of SO_2 Control for Industrial Coal-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Flue Gas Desulfurization / Scrubber / Spray Dryer	10	0.06 – 0.12
Limestone Injection	10	0.055 – 0.114
Low Sulfur Coal	4	0.06 – 1.2

RBLC Review

A review of similar units in the RBLC indicates flue gas desulfurization and low sulfur coal are the principle SO_2 control technologies installed on industrial coal-fired boilers. The lowest SO_2 emission rate in the RBLC is 0.055 lb/MMBtu.

Step 1- Identification of SO_2 Control Technology for the Coal-Fired Boilers

From research, the Department identified the following technologies as available for the control of SO_2 emissions from the industrial coal-fired boilers:

(a) Wet Scrubbers

Post combustion flue gas desulfurization techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gasses can be treated using wet, dry, or semi-dry desulfurization processes. In the wet scrubbing system, flue gas is contacted with a solution or slurry of alkaline material in a vessel providing a relatively long residence time. The SO_2 in the flue reacts with the alkali solution or slurry by adsorption and/or absorption mechanisms to form liquid-phase salts. These salts are dried to about one percent free moisture by the heat in the flue gas. These solids are entrained in the flue gas and carried from the dryer to a PM collection device, such as a baghouse.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible. The Department considers flue gas desulfurization with a wet scrubber a technically feasible control technology for the industrial coal-fired boilers.

(b) Spray Dry Absorbers (SDA)

In SDA systems, an aqueous sorbent slurry with a higher sorbent ratio than that of a wet scrubber is injected into the hot flue gases. As the slurry mixes with the flue gas, the water is evaporated and the process forms a dry waste which is collected in a baghouse or electrostatic precipitator. The Department considers flue gas desulfurization with an SDA system a technically feasible control technology for the industrial coal-fired boilers.

(c) Dry Sorbent Injection (DSI)
DSI systems pneumatically inject a powdered sorbent directly into the furnace, the economizer, or the downstream ductwork depending on the temperature and the type of sorbent utilized. The dry waste is removed using a baghouse or electrostatic precipitator. Spray drying technology is less complex mechanically, and no more complex chemically, than wet scrubbing systems. The main advantages of the spray dryer is that this technology avoids two problems associated with wet scrubbing, corrosion and liquid waste treatment. Spray dry scrubbers are mostly used for small to medium capacity boilers and are preferable for retrofits. The Department considers flue gas desulfurization with DSI a technically feasible control technology for the industrial coal-fired boilers.

(d) Low Sulfur Coal
Aurora purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is located 115 miles south of Fairbanks. The coal mined at Usibelli is sub-bituminous coal and has a relatively low sulfur content with guarantees of less than 0.4 percent by weight. Usibelli Coal Data Sheets indicate a range of 0.08 to 0.28 percent Gross As Received (GAR) percent Sulfur (%S). According to the U.S. Geological Survey, coal with less than one percent sulfur is classified as low sulfur coal. The Department considers the use of low sulfur coal a technically feasible control technology for the industrial coal-fired boilers.

(e) Good Combustion Practices (GCPs)
The theory of GCPs was discussed in detail in the NOx BACT for the industrial coal-fired boilers and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control option for the industrial coal-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for Coal-Fired Boilers
All identified control devices are technically feasible for the industrial coal-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for Industrial Coal-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the coal-fired industrial boilers:

(a)	Wet Scrubbers	(99% Control)
(b)	Spray Dry Absorbers	(90% Control)
(c)	Dry Sorbent Injection (Duct Sorbent Injection)	(50 – 80% Control)
(d)	Low Sulfur Coal	(30% Control)
(e)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

Aurora BACT Proposal

Aurora provided an economic analysis of the installation of wet and dry scrubber systems. A summary of the analysis is shown below:

Table 4-2. Aurora Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber (Limestone Forced Oxidation)	830	415	$88,476,054	???	$74,146
Spray Dry Absorber (Lime Spray Dryer)	830	614	$74,161,357	???	???
Dry Sorbent Injection	830	332	$32,500,898	$9,129,760	$27,493
Capital Recovery Factor = 16.275% of total capital investment (10% for a 10 year life cycle)					

Aurora contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of wet scrubbers, semi-dry scrubbers, or dry scrubber systems (dry-sorbent injection) for the coal-fired boilers based on the excessive cost per ton of SO_2 removed per year.

Aurora proposes the following as BACT for SO_2 emissions from the coal-fired boilers:

(a) SO_2 emissions from the coal-fired boilers will be controlled by burning low sulfur coal (less than 0.2% S by weight) at all times the boilers are in operation; and

(b) SO_2 emissions from the coal-fired boilers will not exceed 0.39 lb/MMBtu.

Department Evaluation of BACT for SO_2 Emissions from Industrial Coal-Fired Boilers

The Department revised the cost analysis provided for the installation of wet scrubbers, semi-dry scrubbers (spray dry absorbers), and dry scrubbers (dry sorbent injection) using the combined unrestricted potential to emit for the four coal-fired boilers, a baseline emission rate of 0.39 lb SO_2/MMBtu, a retrofit difficulty factor of 1.5 for a difficult retrofit, a SO_2 removal efficiency of 99%, 90% and 80% for wet scrubbers, spray dry absorbers and dry sorbent injection respectively, and a 15 year equipment life. A summary of the analysis is shown below:

Table 4-3. Department Economic Analysis for Technically Feasible SO_2 Controls

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	849	840	$65,957,875	$12,160,961	$14,469
Spray Dry Absorbers	849	764	$60,270,115	$11,862,577	$15,525
Dry Sorbent Injection	849	679	$12,332,076	$4,284,104	$6,308
Capital Recovery Factor = 0.1098 (7% interest rate for a 15 year equipment life)					

The Department's preliminary economic analysis indicates the level of SO_2 reduction justifies the use of dry sorbent injection as BACT for the coal-fired boilers located in the Serious PM-2.5 nonattainment area.

Step 5 - Preliminary Selection of SO_2 BACT for the Industrial Coal-Fired Boilers

The Department's preliminary finding is that BACT for SO_2 emissions from the coal-fired boilers is as follows:

(a) SO_2 emissions from EUs 4 through 7 shall be controlled by operating and maintaining dry sorbent injection at all times the units are in operation;

(b) SO_2 emissions from EUs 4 through 7 shall not exceed 0.078 lb/MMBtu averaged over a 3-hour period;

(c) SO_2 emissions from EUs 4 through 7 shall be controlled by burning low sulfur at all times the units are in operation; and

(d) Initial compliance with the SO_2 emission rate for the coal-fired boilers will be demonstrated by conducting a performance test to obtain an emission rate.

Table 4-4 lists the proposed SO_2 BACT determination for this facility along with those for other coal-fired boilers in the Serious PM-2.5 nonattainment area.

Table 4-4. Comparison of SO_2 BACT for Coal-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	6 Coal-Fired Boilers	1380 MMBtu/hr (combined)	0.092 lb/MMBtu[10]	Dry Sorbent Injection Limited Operation Low Sulfur Coal
UAF	Dual Fuel-Fired Boiler	295.6 MMBtu/hr	0.02 lb/MMBtu	Limestone Injection Dry Sorbent Injection Low Sulfur Coal
Chena	4 Coal-Fired Boilers	497 MMBtu/hr (combined)	0.078 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal

[10] Calculated using an 80 percent SO_2 control efficiency, assuming a baseline of 0.46 lb SO_2 / ton (AP-42 Table 1.1-3 and 0.2 % S wt.) and a higher heating value of 7,600 Btu/lb for Healy coal.

5. BACT DETERMINATION SUMMARY

Table 5-1. Proposed NOx BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.10 lb/ MMBtu	Selective Catalytic Reduction
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		

Table 5-2. Proposed SO_2 BACT Limits

EU ID	Description	Rating/Size	Proposed BACT Limit	Proposed BACT Control
4	Chena 1 Coal Fired Boiler	76 MMBtu/hr	0.078 lb/MMBtu	Dry Sorbent Injection Low Sulfur Coal
5	Chena 2 Coal Fired Boiler	76 MMBtu/hr		
6	Chena 3 Coal Fired Boiler	76 MMBtu/hr		
7	Chena 5 Coal Fired Boiler	269 MMBtu/hr		