University of Alaska Fairbanks Campus Power Plant BACT Appendix

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2018-09-13 ADEC Request for Additional Information for UAF BACT Analysis 091018.pdf
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2018-09-13 EPA Comments on ADEC Preliminary Draft SIP Dev.pdf
2018-09-13 Request for Additional Information for the BACT Technical Memorandum for UAF.pdf
2018-11-01 UAF response to ADEC BACT Information Request.pdf
2019-04-23 UAF Response to BACT-SO2 Emissions.pdf
2019-04-29 UAF Response to BACT-SO2 Emissions.pdf
2019-05-10 UAF Attachments OCR.pdf
2019-05-10 UAF BACT Determination.pdf
2019-07-26 Frances Isgrigg e-mail UAF Serious SIP Comments 7-26-19.pdf
2019-07-26 Kerynn Fisher e-mail UAF comments - Fairbanks PM2.5 - Draft SIP 7-26-19.pdf
2019-11-13 Final UAF BACT Determination.pdf
2019-11-13 Final UAF Response To Comments.pdf

The following documents are included in the BACT but not listed in this appendix due to their electronic nature:

2017-01-24 UAF_BACT_NOx_Tables_3-X (UAF).xlsx
2017-02-08 UAF_BACT_PM2.5_Tables_4-X (UAF).xlsx
2017-02-08 UAF_BACT_Tables_1-2_thru_1-5_and_Summary (UAF).xlsx
2018-11-20 UAF_BACT_SO2_Tables_5-X (UAF).xlsx
2019-11-13 UAF EU3 LNB Economic Analysis (ADEC).xlsx
2019-11-13 UAF EU3 SCR Economic Analysis (ADEC).xlsx
2019-11-13 UAF SCR Economic Analysis (ADEC).xlsm
2019-11-13 UAF SNCR Economic Analysis (ADEC).xlsm
2019-11-13 UAF SO2 Controls Economic Analyses (ADEC).xlsx

IPM Model – Revisions to Cost and Performance for APC Technologies

SDA FGD Cost Development Methodology

FINAL

August 2010

Project 12301-007

Perrin Quarles Associates, Inc.

Prepared by

Sargent & Lundy LLC

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This analysis ("Deliverable") was prepared by Sargent & Lundy, L.L.C. ("S&L"), expressly for the sole use of Perrin Quarles Associates, Inc. ("Client") in accordance with the agreement between S&L and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) S&L prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by S&L; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

This work was funded and reviewed by the U.S. Environmental Protection Agency under the supervision of William A. Stevens, Senior Advisor – Power Technologies. Additional input and review was provided by Dr. Jim Staudt, President of Andover Technology Partners.

SDA FGD Cost Development Methodology – Final

Establishment of Cost Basis

Cost data for the SDA FGD systems was more limited than that for the wet FGD systems. A similar trend with generating capacity is generally seen between the wet and SDA system. The same generating capacity relationship was used for the wet and SDA cost estimation.

A least squares curve fit of proprietary in-house cost data was defined as a "typical" SDA FGD retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufactures of SDA FGD systems, are 0.06 lb/MMBtu. The typical SDA FGD retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9800 Btu/kWh;
- SO_2 Rate = 2.0 lb/MMBtu;
- Type of Coal = PRB; and
- Project Execution = Multiple lump sum contracts; and
- Recommended SO_2 emission floor = 0.08 lb/MMBtu.

Units below 50 MW will typically not install an SDA FGD system. Sulfur reductions for the small units would be accomplished by; treating smaller units at a single site with one SDA FGD system, switching to a lower sulfur coal, repowering with natural gas, dry sorbent injection, and/or a reduction in operating hours. Capital costs of approximately $800/kW may be used for units below 50 MW under the premise that these will be combined.

Based on the typical SDA FGD performance, the technology should not be applied to fuels with more than 3 lb SO_2/MMBtu and the cost estimator should be limited to fuels with less than 3 lb SO_2/MMBtu.

An alternate dry technology, circulating dry scrubber (CDS), can meet removals of 98% or greater over a large range of inlet sulfur concentrations. It should be noted that the lowest SO_2 emission guarantees for a CDS FGD system are 0.04 lb/MMBtu.

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The gross unit size in MW (equivalent acfm) and sulfur content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to difficulty in construction of the system must be defined. The costs herein could increase significantly for congested sites. The unit gross heat rate will factor into the amount of flue gas generated and ultimately the size of the absorber, reagent preparation, waste handling, and balance of plant costs. The SO_2 rate will have the greatest influence on the reagent handling and waste handling facilities. The type of fuel (Bituminous, PRB, or Lignite) will influence the flue gas quantities as a result of the different typical heating values.

SDA FGD Cost Development Methodology – Final

Outputs

Total Project Costs (TPC)

First the base installed costs are calculated for each required module (BM_). The base installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Average retrofit difficulty.

The modules are:

BMR =	Base absorber island cost
BMF =	Base reagent preparation and waste recycle/handling cost
BMB =	Base balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc.
BM =	BMR + BMF + BMB

The total base installed cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

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The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures. Table 1 contains an example capital cost estimation.

SDA FGD Cost Development Methodology – Final

Table 1. Example Capital Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000

Capital Cost Calculation			**Example**	**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMR ($) =	if(A>600 then (A*92000) else 566000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$	33,953,000	Base module absorber island cost
BMF ($) =	if(A>600 then (A*48700) else 300000*(A^0.716))*B*(D*G)^0.2	$	20,379,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if(A>600 then (A*129900) else 799000*(A^0.716))*B*(F*G)^0.4	$	47,988,000	Base module balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$	102,320,000	Total Base module cost including retrofit factor
BM ($/KW) =			341	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	10,232,000	Engineering and Construction Management costs
A2 = 10% of BM		$	10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	10,232,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**133,016,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**443**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**139,667,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**466**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**153,634,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**512**	Total project cost per kW

SDA FGD Cost Development Methodology – Final

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the SDA FGD installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs were tabulated on a per kilowatt-year (kW yr) basis.
- In general, 8 additional operators are required for a SDA FGD system. The FOMO was based on the number of additional operations staff required.
- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).
- The administrative labor is a function of the FOMO and FOMM.

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs;
- Additional power required and unit power cost; and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.
- The reagent usage is a function of gross unit size, SO_2 feed rate, and removal efficiency. The estimated reagent usage was based on a sulfur removal efficiency of 95% with a flue gas temperature into the SDA FGD of 300°F and an adiabatic approach to saturation of 30°F. The calcium-to-sulfur stoichiometric ratio varies based on inlet sulfur. The variation in stoichiometric ratio was accounted for in the estimation. The economic estimation is only valid up to 3 lb SO_2/MMBtu inlet. The basis for the lime purity was 90% CaO with the balance being inert material.

SDA FGD Cost Development Methodology – Final

- The waste generation rate is a function of inlet sulfur and calcium to sulfur stoichiometry. Both variables are accounted for in the waste generation estimation. The waste disposal rate is based on 10% moisture in the by-product.

- The additional power required includes increased fan power to account for the added SDA FGD pressure drop. This requirement is a function of gross unit size (actual gas flow rate) and sulfur rate.

- The makeup water rate is a function of gross unit size (actual gas flow rate) and sulfur feed rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Limestone cost in $/ton;
- Waste disposal costs in $/ton;
- Auxiliary power cost in $/kWh;
- Makeup water costs in $/1000 gallon; and
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR =	Variable O&M costs for lime reagent
VOMW =	Variable O&M costs for waste disposal
VOMP =	Variable O&M costs for additional auxiliary power
VOMM =	Variable O&M costs for makeup water

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 2 contains an example O&M cost estimate, while Table 3 is a complete capital and O&M cost estimate worksheet.

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Table 2. Example O&M Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	3.33	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.12	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.16	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**8.61**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	1.37	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**2.40**	

SDA FGD Cost Development Methodology – Final

Table 3. Example Complete Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation			**Example**	**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMR ($) =	if(A>600 then (A*92000) else 566000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$	33,953,000	Base module absorber island cost
BMF ($) =	if(A>600 then (A*48700) else 300000*(A^0.716))*B*(D*G)^0.2	$	20,379,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if(A>600 then (A*129900) else 799000*(A^0.716))*B*(F*G)^0.4	$	47,988,000	Base module balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$	102,320,000	Total Base module cost including retrofit factor
BM ($/KW) =			341	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	10,232,000	Engineering and Construction Management costs
A2 = 10% of BM		$	10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	10,232,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**133,016,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**443**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**139,667,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**466**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**153,634,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**512**	Total project cost per kW

SDA FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	3.33	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.12	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.16	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**8.61**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	1.37	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**2.40**	

IPM Model – Revisions to Cost and Performance for APC Technologies

Wet FGD Cost Development Methodology

FINAL

August 2010

Project 12301-007

Perrin Quarles Associates, Inc.

Prepared by

Sargent & Lundy LLC

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This work was funded and reviewed by the U.S. Environmental Protection Agency under the supervision of William A. Stevens, Senior Advisor – Power Technologies. Additional input and review was provided by Dr. Jim Staudt, President of Andover Technology Partners.

Wet FGD Cost Development Methodology – Final

Establishment of Cost Basis

The 2004 to 2006 industry cost estimates for wet FGD units from the "Analysis of MOG and Ladco's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls" prepared for Midwest Ozone Group (MOG) were compared to the Sargent & Lundy LLC (S&L) in-house database. Agreement of the data was confirmed between the industry estimates and the S&L data.

The MOG and S&L cost data from 2004 to 2006 were converted to 2007 dollars based on the Chemical Engineering Plant Index (CEPI) data. Additional proprietary S&L in-house data from 2007 were included to confirm the index validity.

Cost data from the various sources showed similar trends versus generating capacity. Escalation based on the CEPI was deemed acceptable. All three data sources were combined so as to provide a representative wet FGD cost basis.

The 2004 through 2007 data were escalated to 2009 to represent market conditions.

The least squares curve fit of the data was defined as a "typical" wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufactures of wet FGD systems, are 0.04 lb/MMBtu. The typical wet FGD retrofit was based on:

- Retrofit Difficulty =1 (Average retrofit difficulty) ;
- Gross Heat Rate = 9500 Btu/kWh;
- SO_2 Rate = 3.0 lb/MMBtu;
- Type of Coal = Bituminous;
- Project Execution = Multiple lump sum contracts; and
- Recommended SO_2 emission floor = 98% removal efficiency or 0.06 lb/MMBtu.

Units below 100 MW will typically not install a wet FGD system. Sulfur reductions for the small units would be accomplished by; treating smaller units at a single site with one wet FGD system, switching to a lower sulfur coal, repowering with natural gas, dry sorbent injection, and/or a reduction in operating hours. Capital costs of approximately $750/kW may be used for units below 100 MW under the premise that these will be combined.

Wet FGD Cost Development Methodology – Final

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The gross unit size in MW (equivalent acfm) and sulfur content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to difficulty in construction of the system must be defined. The costs herein could increase significantly for congested sites. The gross unit heat rate will factor into the amount of flue gas generated and ultimately the size of the absorber, reagent preparation, waste handling, and balance of plant costs. The SO_2 rate will have the greatest influence on the reagent handling and waste handling facilities. The type of fuel (Bituminous, PRB, or Lignite) will influence the flue gas quantities as a result of the different typical heating values.

The evaluation includes a user selected option for a wastewater treatment facility. The base capital cost includes minor physical and chemical wastewater treatment. However, in the future more extensive wastewater handling may be required. Although an option for wastewater treatment is provided, no logic has been developed to accommodate the additional wastewater treatment costs.

Outputs

Total Project Costs (TPC)

First the base installed costs are calculated for each required module (BM_). The base installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical;
- Minor physical and chemical wastewater treatment (WWT); and
- Average retrofit difficulty.

The modules are:

BMR =	Base absorber island cost
BMF =	Base reagent preparation cost
BMW =	Base waste handling cost
BMB =	Base balance of plan costs including: ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc.
BMWW =	Base wastewater treatment facility for future use.
BM =	BMR + BMF + BMW + BMB

Wet FGD Cost Development Methodology – Final

The total base installed cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures. Table 1 contains an example capital cost estimation.

Wet FGD Cost Development Methodology – Final

Table 1. Example Capital Cost Estimate for the Wet FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	3	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty				
BMR ($) =	550000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$	46,024,000	Base absorber island cost
BMF ($) =	190000*(B)*((D*G)^0.3)*(A^0.716)	$	22,267,000	Base reagent preparation cost
BMW ($) =	100000*(B)*((D*G)^0.45)*(A^0.716)	$	13,713,000	Base waste handling cost
BMB ($) =	1010000*(B)*((F*G)^0.4)*(A^0.716)	$	84,698,000	Base balance of plan costs including: ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc…
BMWW ($) =		$	-	Base wastewater treatment facility, beyond minor physical/chemical treatment
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$	166,702,000	Total base cost including retrofit factor
BM ($/KW) =			333	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	16,670,000	Engineering and Construction Management costs
A2 = 10% of BM		$	16,670,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	16,670,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**216,712,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**433**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	10,836,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**227,548,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**455**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	22,755,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**250,303,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**501**	Total project cost per kW

Wet FGD Cost Development Methodology – Final

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the wet FGD installation. A future fixed O&M cost category is included to account for an extensive wastewater treatment facility. At this time, the wastewater treatment fixed O&M (FOMWW) is not estimated and is included at zero dollars. The FOM is the sum of the FOMO, FOMM, FOMA, and FOMWW.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs were tabulated on a per kilowatt-year (kW yr) basis.

- In general, 12 additional operators are required for a 500 MW or smaller installation. Units larger than 500 MW require a total of 16 additional operators. The FOMO was based on the number of additional operations staff required as a function of generating capacity.

- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).

- The administrative labor is a function of the FOMO and FOMM.

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs;
- Additional power required and unit power cost; and
- Makeup water required and unit water cost.

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Wet FGD Cost Development Methodology – Final

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.

- The reagent usage is a function of gross unit size, SO_2 feed rate, and removal efficiency. The estimated reagent usage was based on a sulfur removal efficiency of 98% and a calcium-to-sulfur stoichiometric ratio of 1.03. The basis for the limestone purity was 90% $CaCO_3$ with the balance being inert material.

- The waste generation rate is directly proportional to the reagent usage and is estimated based on 10% moisture in the by-product.

- The additional power required includes increased fan power to account for the added wet FGD pressure drop. This requirement is a function of gross unit size (actual gas flow rate) and sulfur rate.

- The makeup water rate is a function of gross unit size (actual gas flow rate) and sulfur feed rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Limestone cost in $/ton;
- Waste disposal costs in $/ton;
- Auxiliary power cost in $/kWh;
- Makeup water costs in $/1000 gallon; and
- Operating labor rate (including all benefits) in $/hr.

Wet FGD Cost Development Methodology – Final

The variables that contribute to the overall VOM are:

VOMR =	Variable O&M costs for limestone reagent
VOMW =	Variable O&M costs for waste disposal
VOMP =	Variable O&M costs for additional auxiliary power
VOMM =	Variable O&M costs for makeup water
VOMWW =	Variable O&M costs for wastewater treatment

A future variable O&M cost category is included to account for an extensive wastewater treatment facility. At this time, the wastewater treatment variable O&M (VOMWW) is not estimated and is included at zero dollars.

The total VOM is the sum of VOMR, VOMW, VOMP, VOMM, and VOMWW. Table 2 contains an example O&M cost estimate, while Table 3 is a complete capital and O&M cost estimate worksheet.

Wet FGD Cost Development Methodology – Final

Table 2. Example O&M Cost Estimate for the Wet FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	3	<--- User Input
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost			
FOMO ($/kW yr) = (if MW>500 then 16 additional operators else 12 operators)*2080*T/(A*1000)	$	3.00	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.00	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.15	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =	$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**8.15**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = K*P/A	$	0.37	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	$	1.36	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.08	Variable O&M costs for makeup water
VOMWW ($/MWh) =	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**$**	**1.81**	

Table 3. Example Complete Cost Estimate for the Wet FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	3	<--- User Input
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation			**Example**	**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty				
BMR ($) =	550000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$	46,024,000	Base absorber island cost
BMF ($) =	190000*(B)*((D*G)^0.3)*(A^0.716)	$	22,267,000	Base reagent preparation cost
BMW ($) =	100000*(B)*((D*G)^0.45)*(A^0.716)	$	13,713,000	Base waste handling cost
BMB ($) =	1010000*(B)*((F*G)^0.4)*(A^0.716)	$	84,698,000	Base balance of plan costs including: ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc…
BMWW ($) =		$	-	Base wastewater treatment facility, beyond minor physical/chemical treatment
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$	166,702,000	Total base cost including retrofit factor
BM ($/KW) =			333	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	16,670,000	Engineering and Construction Management costs
A2 = 10% of BM		$	16,670,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	16,670,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**216,712,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**433**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	10,836,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**227,548,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**455**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	22,755,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**250,303,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**501**	Total project cost per kW

Sargent & Lundy LLC

IPM Model – Revisions to Cost and Performance for APC Technologies

Project No. 12301-007
August 20, 2010

Wet FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	3	<--- User Input
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost			
FOMO ($/kW yr) = (if MW>500 then 16 additional operators else 12 operators)*2080*T/(A*1000)	$	3.00	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.00	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.15	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =	$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**8.15**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = K*P/A	$	0.37	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	$	1.36	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.08	Variable O&M costs for makeup water
VOMWW ($/MWh) =	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**$**	**1.81**	

IPM Model – Updates to Cost and Performance for APC Technologies

Dry Sorbent Injection for SO_2 Control Cost Development Methodology

Final

March 2013

Project 12847-002

Systems Research and Applications Corporation

Prepared by

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Dry Sorbent Injection for SO_2 Control
Cost Development Methodology

Technology Description

Dry sorbent injection (DSI) is a viable technology for moderate SO_2 reduction on coal fired boilers. Demonstrations and recent utility testing have shown SO_2 removals greater than 80% for systems using sodium based sorbents. The most common sodium based sorbent is Trona.

The level of removal for Trona can vary from 0 to 90% depending on the Normalized Stoichiometric Ratio (NSR) and particulate capture device. NSR is defined as:

$$\frac{\left(\frac{\text{(moles of Na injected)}}{\text{(moles of } SO_2 \text{ in flue gas)}}\right)}{\text{(theoretical moles of Na required)}}$$

The target removal efficiency is a requirement from the utility and is independent of unit size. The costs for a DSI system are primarily dependent on sorbent feed rate which is a function of NSR and SO_2 mass feed rate per hour. Therefore, the cost estimation was based on sorbent feed rate and not on unit size.

The sorbent solids can be collected in either an ESP or a baghouse. Baghouses generally achieve greater SO_2 removal efficiencies than ESPs by virtue of the filter cake on the bags, which allows for longer reaction time between the sorbent solids and the flue gas. For a given removal efficiency with Trona, the NSR is reduced when a baghouse is used for particulate capture.

The dry sorbent capture ability is also a function of particle surface area. To increase the particle surface area, the sorbent must be injected into a relatively hot flue gas. Heating the solids produces micropores on the particle surface which greatly improve the sulfur capture ability. For Trona, the sorbent should be injected into flue gas above 275°F to maximize the micropore structure. However, if the flue gas is too hot (greater than 800°F), the solids may sinter and surface area is reduced thus lowering the SO_2 removal efficiency of the sorbent.

Another way to increase surface area is to mechanically reduce the particle size by grinding the sorbent. Typical Trona is delivered unmilled. The ore is ground such that the unmilled product has an average size around 30 μm. Commercial testing has shown that the reactivity of the Trona can be increased when the sorbent is ground to less than 30 μm. In the cost estimating methodology, the Trona is always delivered in the unmilled state. To mill the Trona, in-line mills are continuously used during the Trona injection process. Therefore, the delivered cost of the Trona will not change, only the reactivity and usage changes as the Trona is milled.

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Ultimately, the NSR required for a given removal is a function of Trona particle size and particulate capture equipment. Either as delivered Trona (around 30 µm average size) or in-line milled Trona (around 15 µm average size) can be chosen for injection in the cost program. The average Trona particle size and the type of particulate removal both contribute to the predicted Trona feed rate.

Establishment of Cost Basis

For the wet or SDA FGD systems, the sulfur removal is generally specified at the maximum achievable level. With those systems, costs are primarily a function of plant size and sulfur rate. However, the DSI systems are quite different. The major cost for the DSI system is the sorbent itself. The sorbent feed rate is a function of sulfur rate, particulate collection device, and removal efficiency. To account for all of the variables, the capital cost was established based on a sorbent feed rate. The sorbent feed rate is calculated from user input variables. Cost data for several DSI systems was reviewed and a relationship was developed for the capital costs of the system on a sorbent feed rate basis.

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The sulfur feed rate and NSR are the major variables for the cost estimate. The NSR is a function of:

- Removal efficiency;
- Trona particle size; and
- Particulate capture device.

A retrofit factor that equates to difficulty in construction of the system must be defined. The gross unit size and gross heat rate will factor into the amount of sulfur generated.

Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. When the sorbent is captured in an ESP, a 40 to 50% SO_2 removal is typically achieved without an increase in particulate emissions. A higher efficiency (70 – 75%) is generally achieved with a baghouse. The DSI technology should not be applied to fuels with a sulfur content of greater than 2 lb SO_2/MMBtu.

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Units with a baghouse and limited NOx control that target a high SO_2 removal efficiency with sodium sorbents may experience a brown plume resulting from the conversion of NO to NO_2. The formation of NO_2 would then have to be addressed by adding adsorbent into the flue gas. However, many coal-fired units control NOx to a sufficiently low level that a brown plume should not be an issue with sodium-based DSI. Therefore, this study does not incorporate any additional costs to control NO_2.

The equations provided in the cost methodology spreadsheet allow the user to input the required removal efficiency, within the limits of the technology. To simplify the correlation, the removal with an ESP should be set at 50% and 70% with a baghouse. The simplified sorbent NSR would then be:

For an ESP at the target 50% removal:
Unmilled Trona NSR = 2.85
Milled Trona NSR = 1.40

For a baghouse at the target 70% removal:
Unmilled Trona NSR = 2.00
Milled Trona NSR = 1.55

The correlation could be further simplified by assuming that only milled Trona is used. The current trend in the industry is to use in-line milling of the Trona to improve the utilization. For a minor increase in capital, the milling can greatly reduce the variable operating expenses. It is recommended that only milled Trona be considered in the simplified model.

Outputs

Total Project Costs (TPC)

First the base installed cost for the complete DSI system is calculated (BM). The base installed cost includes:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Average retrofit difficulty.

Dry Sorbent Injection for SO_2 Control
Cost Development Methodology

The base module cost is adjusted by the selection of in-line milling equipment. The base installed cost is then increased by:

- Engineering and construction management costs at 5% of the BM cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 5% of the BM cost; and
- Contractor profit and fees at 5% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 0% of the CECC and owner's costs as these projects are expected to be completed in less than a year.

The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Fixed O&M (FOM)
The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the DSI installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs were tabulated on a per kilowatt-year (kW-yr) basis.

- In general, 2 additional operators are required for a DSI system. The FOMO was based on the number of additional operations staff required.

- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).

- The administrative labor is a function of the FOMO and FOMM.

Variable O&M (VOM)
Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs; and
- Additional power required and unit power cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.

- The reagent usage is a function of NSR and SO_2 feed rate. The gross unit size and gross heat rate factor multiplied by the SO_2 rate determine the SO_2 feed rate. The estimated NSR is a function of removal efficiency required. The basis for the total reagent rate is a Trona purity of 95%.

- The waste generation rate is a function of the Trona feed rate and is adjusted for the excess sorbent fed. The waste generation rate is based on reaction products of Na_2SO_4 and unreacted dry sorbent as Na_2CO_3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.

- With the addition of a sodium sorbent that is captured in the same particulate control device as the fly ash, any fly ash produced must be landfilled. Typical ash contents for each fuel are used to calculate a total fly ash production rate. The fly ash production is added to the sorbent waste to account for a total waste stream in the O&M analysis.

- The user has the ability to remove fly ash from the waste disposal cost to reflect the situation where the unit has separate particulate capture devices for fly ash and dry sorbent.

- When a baghouse is installed downstream of an ESP, the sodium sorbent could be injected before the baghouse with no effect on the fly ash collection.

Dry Sorbent Injection for SO_2 Control
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In that case, the disposal costs of the sodium only waste should be increased to account for the increased difficulty in handling the pure sodium waste product.

- The additional power required includes air blowers for the injection system, drying equipment for the transport air, and in-line Trona milling equipment as needed.

- The additional power is reported as a percent of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Trona cost in $/ton;
- Waste disposal costs in $/ton that should vary with the type of waste being disposed;
- Auxiliary power cost in $/kWh;
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for trona reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

The total VOM is the sum of VOMR, VOMW, and VOMP. The additional auxiliary power requirement is also reported as a percentage of the total gross power of the unit. Table 1 contains an example of the complete capital and O&M cost estimate worksheet.

Dry Sorbent Injection for SO_2 Control
Cost Development Methodology

Table 1. Example Complete Cost Estimate for a DSI System

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Milled Trona	G		☑ TRUE	Based on in-line milling equipment
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if (H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if (H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if (H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if (H<40,0.0160*H,0.208e^(0.0281*H))
Trona Feed Rate	M	(ton/hr)	16.33	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	11.65	(0.7387-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.
Fly Ash Waste Rate Include in VOM? ☑	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Aux Power **Include in VOM?** ☑	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A
Trona Cost	R	($/ton)	170	<--- User Input
Waste Disposal Cost	S	($/ton)	50	<--- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more dificult to dispose = $100)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2012 dollars

Capital Cost Calculation	Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	18,348,000	Base DSI module includes all equipment from unloading to injection
BM ($/KW) =		37	Base module cost per kW
Total Project Cost			
A1 = 5% of BM	$	917,000	Engineering and Construction Management costs
A2 = 5% of BM	$	917,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM	$	917,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**21,099,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**42**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	$	1,055,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**22,154,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**44**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**22,154,000**	Total project cost
TPC ($/kW) =		**44**	Total project cost per kW

Dry Sorbent Injection for SO_2 Control
Cost Development Methodology

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Milled Trona	G		☑ TRUE	Based on in-line milling equipment
Removal Target	H	(%)	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
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Trona Cost	R	($/ton)	170	<--- User Input
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Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Operating Labor Rate	U	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2012 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (2 additional operators)*2080*U/(A*1000)	$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.37	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.89**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*R/A	$	5.55	Variable O&M costs for Trona reagent
VOMW ($/MWh) = (N+P)*S/A	$	3.24	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10	$	0.39	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**9.18**	

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
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April 24, 2015

Frances Isgrigg
Director of Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Voluntary BACT Analysis for Fairbanks Campus Power Plant

Dear Ms. Isgrigg:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

<u>Background</u>

Clean Air

EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98^{th} percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

- Serious Area SIP inventory development starts: January, 2015
- BACT kick off meeting: March 5, 2015
- Submit initial BACT results to ADEC: December, 2015
- Submit complete/final BACT analysis to ADEC: March, 2016
- Serious Area SIP modeling by ADEC starts: March, 2016
- Serious Area designation by EPA (Expected): June, 2016
- Serious Area SIP draft: December, 2016
- Serious Area SIP public notice period: February, 2017
- Serious Area SIP submitted by ADEC to EPA: December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality

$PM_{2.5}$ Serious Nonattainment Area BACT Analysis Protocol for the UAF Campus Stationary Source

July 2015

Prepared by:

CONTENTS

TABLES

APPENDICES

ACRONYMS

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
BACM	Best Available Control Measures
BACT	Best Available Control Technology
CAA	Clean Air Act
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
EPA	U.S. Environmental Protection Agency
EU	Emission Unit
EUAC	Equivalent Uniform Annual Cost
FNSB	Fairbanks North Star Borough
ID	Identification
LAER	Lowest Achievable Emission Rate
NH_3	Ammonia
NO_X	Total Nitrogen Oxides
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSPS	New Source Performance Standards
NSR	New Source Review
$PM_{2.5}$	Particulate matter with a diameter less than or equal to 2.5 micrometers
PM_{10}	Particulate matter with a diameter less than or equal to 10 micrometers
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SIP	State Implementation Plan
SLR	SLR International Corporation
SO_2	Sulfur Dioxide
TAR	Technical Analysis Report
tpy	Tons per Year
UAF	University of Alaska Fairbanks
VOC	Volatile Organic Compounds

INTRODUCTION

The U.S. Environmental Protection Agency (EPA) designated portions of the Fairbanks North Star Borough (FNSB), including the City of Fairbanks and the City of North Pole, as a moderate nonattainment area for fine particulate matter ($PM_{2.5}$, particulate matter with a diameter less than 2.5 micrometers in diameter) in 2009 [74 FR 58,688; 13 November 2009]. This designation is for the 24-hour averaging period. The Alaska Department of Environmental Conservation (ADEC) expects EPA to change this designation to serious in or about June 2016 based on the failure to attain compliance with the 24-hour average $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) through the measures implemented to bring the moderate nonattainment area into attainment.

On March 23, 2015, EPA proposed changes to 40 Code of Federal Regulations (CFR) 51, Subpart Z, Provisions for Implementation of $PM_{2.5}$ National Ambient Air Quality Standards. These proposed changes, once finalized, will include the attainment plan submittal requirements that ADEC must address in the plan to bring the FNSB Serious $PM_{2.5}$ nonattainment area into attainment. In proposing this rule, EPA presented and solicited comments about several plan alternatives. As a result, the requirements which may be promulgated in the revised 40 CFR 51 Subpart Z are difficult to anticipate at this time.

One element of the attainment plan that ADEC must prepare for EPA approval is likely to be determining Best Available Control Technology (BACT) for certain stationary sources located in the nonattainment area. The University of Alaska Fairbanks (UAF) Campus is likely to be a stationary source for which a BACT analysis is required. In a letter dated April 24, 2015, ADEC asked UAF to voluntarily prepare a BACT analysis that ADEC could then incorporate into the attainment planning process. ADEC made this request because the agency “has neither the funding nor the in depth knowledge of your facility’s infrastructure to determine the most appropriate BACT for your facility.” UAF is responding to this request by submitting this BACT analysis protocol to ADEC for approval. Once the protocol is approved, UAF will move forward with voluntarily preparing the requested BACT analysis with the intent to submit the initial BACT analysis to ADEC no later than the requested December 2015 deadline.

1. BACT ANALYSIS APPROACH

The methodology that will be used for identifying BACT will be the five step "top-down" process set forth in the proposed *EPA New Source Review Rule Revisions* (1996) and is outlined in the following subsections.

1.1 IDENTIFY ALL CONTROL TECHNOLOGIES

The first step of the BACT analysis will be to survey alternative control techniques and identify all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions units and pollutants under evaluation. The following guidelines are used to identify available control options:

> The technology should be "demonstrated in practice". The control technology should have been installed and operating at a minimum of 50 percent of capacity for six months, and the performance should have been verified with a test or operational data at 90 percent of operational capacity.
>
> Controls applied to similar source categories, gas streams, and innovative control technologies should be examined. Process controls, such as combustion modifications, that are currently available from a supplier should be reviewed.

1.2 ELIMINATE TECHNICALLY INFEASIBLE CONTROL OPTIONS

In step two, the technical feasibility of each available control option will be evaluated based on source-specific factors. The use of control options, which would clearly result in technical difficulties precluding their successful use, will be deemed technically infeasible.

1.3 RANK REMAINING CONTROL OPTIONS BY EFFECTIVENESS

In step three, the effectiveness of control alternatives will be determined for all options not eliminated in step two. Control options are then ranked "top-down" in order of overall control effectiveness for the pollutant under review. Control options which would result in emissions that exceed Federal New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutants (NESHAP) applicable to the source can be eliminated.

1.4 EVALUATE MOST EFFECTIVE CONTROL OPTIONS

In step four, the energy, environmental, and economic impacts of control options will be considered, beginning with the top-ranked control alternative. If the most effective control option is shown to be inappropriate due to adverse impacts, that option will be eliminated and the next most stringent alternative will be evaluated. If the most stringent technology is selected as BACT, continuing the analysis will not be necessary.

1.5 SELECT BACT

Finally, in step five, the most effective control option not eliminated in step four will be proposed as BACT for the pollutant and emission unit under review.

The basis for comparing the economic impacts of control scenarios will be cost effectiveness. This value is defined as the total net annualized cost of control, divided by the tons of pollutant removed per year, for each control technique. Annualized costs include the annualized capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, replacement parts, overhead, raw materials, and utilities.

Capital costs include both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, startup costs and contingencies.

For the analysis, all costs are expressed as an annualized cost, and cost-effectiveness values are then calculated. This approach of amortizing the investment into equal end-of-year annual costs is termed the Equivalent Uniform Annual Cost (EUAC). This approach is the EPA recommended method for estimating control costs. Templates for cost estimation purposes can be found in Appendix B.

For the purposes of the $PM_{2.5}$ Serious nonattainment BACT analysis, if a particular control technology is eliminated based on economic factors, the assumption will be made that the control technology is also uneconomic for smaller emission units.

1.6 DOCUMENTATION

Supporting documentation for the nonattainment BACT analysis will be provided and will include data to support control effectiveness assertions, cost estimates, and justification for eliminating control options based environmental or economic determinations, if applicable.

2. STATIONARY SOURCE DESCRIPTION

This section provides a description of the UAF Campus stationary source. This description is based on information in Operating Permit No. AQ0316TVP02, Revision 1, the Statement of Basis (SOB) associated with that permit, Construction Permit No. AQ0316CPT01, the Technical Analysis Report (TAR) associated with that permit, and Minor Source Permit Nos. AQ0316MSS03 and AQ0316MSS04. Section 2.1 provides a BACT applicability analysis. Section 2.2 provides a description of the UAF stationary source and a detailed emission unit inventory.

2.1 BACT APPLICABILITY ANALYSIS

A stationary source in a serious nonattainment area that has potential emissions of more than 70 tons per year (tpy) of direct $PM_{2.5}$ or any $PM_{2.5}$ precursor is a major stationary source for serious $PM_{2.5}$ nonattainment purposes. Major stationary sources are expected to be subject to a BACT review. Table 1 provides the potential emissions for $PM_{2.5}$, sulfur dioxide (SO_2), nitrogen oxides (NO_X), volatile organic compounds (VOC), and ammonia (NH_3) for the UAF stationary source. Table 1 is based on information in the SOB for Operating Permit No. AQ0316TVP02, Revision 1 and the TAR for Construction Permit No. AQ0316CPT01. UAF plans to replace the existing coal-fired boilers, which are currently identified in Operating Permit No. AQ0316TVP02, Revision 1 as EUs 1 and 2, with two new dual fuel-fired boilers. UAF has been authorized to install and operate these new boilers under Construction Permit No. AQ0316CPT01.

Based on the potential emissions provided in Table 1, the stationary source potential NO_X and SO_2 emissions exceed the 70 tpy major source threshold, independent of whether the existing coal-fired boilers are replaced. Given the uncertainties associated with the proposed changes to 40 CFR 51 Subpart Z, BACT analyses will be prepared for direct $PM_{2.5}$ and for NO_X and SO_2 as $PM_{2.5}$ precursors. BACT analyses will not be prepared for VOC and NH_3 based on the low potential emission values for those two air pollutants.

Table 1. UAF Serious Nonattainment Area Major Source Applicability

Pollutant	Potential Emissions		Major Source?
	Existing UAF Campus Emission Units[1]	Proposed UAF Campus Emission Units[2]	>70 tpy PTE
$PM_{2.5}$	(PM_{10}=17)	46 (PM_{10}=54)	No
SO_2	858	765	Yes
NO_X	637	512	Yes
VOC	11	23	No
NH_3	<1[3]	<1[3]	No

[1] From Table D of the SOB for AQ0316TVP02, Revision 1.
[2] From Table 3 of the TAR for AQ0316CPT01.
[3] Estimated potential emissions based on 0.565 lb/1,000 ton emission factor from WebFIRE.

2.2 UAF EMISSION UNIT INVENTORY

Table 2 provides the currently permitted emission unit inventory for the UAF Campus stationary source. The inventory includes the existing emission units that UAF is authorized to operate under Operating Permit No. AQ0316TVP02, Revision 1, emission units listed in Minor Source Permit Nos. AQ0316MSS03 and AQ0316MSS04, and the planned emission units that UAF is authorized to install and operate under Construction Permit No. AQ0316CPT01. The UAF Campus stationary source emission unit inventory includes equipment used for central heat and power, specifically two coal-fired boilers, two dual fuel-fired boilers (diesel and natural gas), and a diesel-fired backup generator engine. An incinerator for medical and infectious waste disposal, three diesel-fired boilers, and one diesel-fired engine are also present at the facility. UAF is authorized to install and operate two dual fuel-fired circulating fluidized bed (CFB) boilers (coal and woody biomass) and associated handling systems under Construction Permit No. AQ0316CPT01. UAF has not yet installed these emission units.

Construction Permit No. AQ0316CPT01 was issued on April 2, 2014, for the replacement of the existing coal-fired boilers (EU IDs 1 and 2) with two new dual fuel-fired boilers (EU IDs 101 and 102) and ancillary equipment (EU IDs 103 through 112). Permit No. AQ0316CPT01, Condition 13, requires UAF to remove one of the existing coal-fired boilers (EU IDs 1 or 2) from service prior to either of EU IDs 101 or 102 becoming fully operational. UAF must also remove the remaining existing boiler (either EU ID 1 or 2) from service prior to the remaining replacement dual fuel-fired boiler (either EU ID 101 or 102) becoming fully operational. UAF anticipates installing the dual fuel-fired boilers (EU IDs 101 and 102) before the end of calendar year 2019, contingent upon the full funding of the project and assuming that no construction delays occur. Because UAF plans to replace the existing coal-fired boilers with the new dual fuel-fired boilers within four years after the FNSB nonattainment area is reclassified as a Serious Area, UAF will prepare a $PM_{2.5}$, NO_X and SO_2 BACT analyses for EU IDs 101 and 102, but not for EU IDs 1 and 2. UAF will prepare a $PM_{2.5}$ BACT analysis for EU IDs 103 through 112, but will not prepare NO_X or SO_2 BACT analyses for those emission units because the units do not emit NO_X or SO_2.

In summary, UAF will prepare $PM_{2.5}$, NO_X and SO_2 BACT analyses for the following emission units:

- EU IDs 3 and 4, dual fuel (diesel and natural gas (NG))-fired boilers,
- EU ID 8, backup diesel-fired internal combustion engine (ICE) generator,
- EU ID 9A, incinerator,
- EU IDs 19 through 21, diesel-fired boilers,
- EU ID 27, diesel-fired ICE generator, and
- EU IDs 101 and 102, the dual fuel-fired circulating fluidized bed (CFB) boilers.

UAF will also prepare a $PM_{2.5}$ BACT analysis for EU IDs 103 through 112.

Table 2. Permitted Facility Emission Unit Inventory

Emission Unit				Fuel Type/ Material	Maximum Capacity	Existing Controls	Permit
ID	Description	Make/Model	Location				
Coal-Fired Boilers							
1	Coal-Fired Boiler	Erie City	FS802	Coal	84.5 MMBtu/hr[1]	Baghouse	AQ0316TVP02, Rev 1
2	Coal-Fired Boiler	Erie City	FS802	Coal	84.5 MMBtu/hr[1]	Baghouse	AQ0316TVP02, Rev 1
Dual Fuel-Fired (Diesel/NG) Boilers							
3	Dual-Fired Boiler	Zurn	FS802	Dual - Diesel and NG[2,3]	180.9 MMBtu/hr	None	AQ0316TVP02, Rev 1
4	Dual-Fired Boiler	Zurn	FS802	Dual - Diesel and NG[3]	180.9 MMBtu/hr[5]	None	AQ0316TVP02, Rev 1
Emergency Generator Engine							
8	Peaking/Backup Generator (DEG) Engine[4]	Fairbanks Morse Colt-Pielstick PC2.6	FS817	Diesel[3]	13,266 hp	SCR	AQ0316TVP02, Rev 1
Incinerator							
9A	BiRD Incinerator	Therm-Tec/G-30P-1H	FS919	Medical/ Infectious Waste	83 lb/hr[1]	None	AQ0316TVP02, Rev 1 & AQ0316MSS04
Diesel-Fired Boilers							
19	BiRD RM 100U3 Boiler #1	Weil McLain/2094W	FS919	ULSD[6]	6.13 MMBtu/hr[7]	None	AQ0316MSS04
20	BiRD RM 100U3 Boiler #2	Weil McLain/2094W	FS919	ULSD[6]	6.13 MMBtu/hr[7]	None	AQ0316MSS04
21	BiRD RM 100U3 Boiler #3	Weil McLain/2094W	FS919	ULSD[6]	6.13 MMBtu/hr[7]	None	AQ0316MSS04
Generator Engine							
27	Alaska Center for Energy and Power Generator Engine	Caterpillar C-15	FS814	Diesel	500 hp	None	AQ0316MSS03

[1] The actual rating is shown. The rating in Permit No. AQ0316TVP02, Revision 1, Table A is incorrect.
[2] EU 3 is permitted as a dual fuel-fired boiler but is currently configured to fire only diesel.
[3] EUs 3, 4, and 8 are authorized to combust coal slurry fuel. Those emission units have not operated on this fuel and will not do so in the future.
[4] EU 8 is currently operated as an emergency engine as opposed to a peaking/backup engine.
[5] EU 4 has a 10 percent capacity factor limit per Condition 17 of Permit No. AQ0316TVP02.
[6] Ultra Low Sulfur Diesel.
[7] The nameplate does not specify whether the rating is based on heat output or heat input; the rating shown assumes 75% boiler efficiency to conservatively estimate the maximum heat input rating.

Table 2. Permitted Facility Emission Unit Inventory (Continued)

Emission Unit				Fuel Type/	Maximum	Existing	Permit
ID	Description	Make/Model	Location	Material	Capacity	Controls	
Dual Fuel-Fired CFB Boilers							
101	Dual Fuel-Fired CFB Boiler No. 1	Babcock & Wilcox/TBD	TBD[8]	Coal/Woody Biomass	185 MMBtu/hr	Dry sorbent injection	AQ0316CPT01
102	Dual Fuel-Fired CFB Boiler No. 2	Babcock & Wilcox/TBD	TBD[8]	Coal/Woody Biomass	185 MMBtu/hr	Dry sorbent injection	AQ0316CPT01
Fugitive Emission Sources							
103	Fuel Handling System for Boiler No. 1	NA[9]	TBD[8]	Particulate Matter	40,000 acfm	Dust collector	AQ0316CPT01
104	Fuel Handling System for Boiler No. 2	NA	TBD[8]	Particulate Matter	40,000 acfm	Dust collector	AQ0316CPT01
105	Limestone Handling System for Boiler No. 1	NA	TBD[8]	Particulate Matter	1,600 acfm	Dust collector	AQ0316CPT01
106	Limestone Handling System for Boiler No. 2	NA	TBD[8]	Particulate Matter	1,600 acfm	Dust collector	AQ0316CPT01
107	Sand Handling System	NA	TBD[8]	Particulate Matter	1,600 acfm	Dust collector	AQ0316CPT01
108	Dry Sorbent Handling System	NA	TBD[8]	Particulate Matter	1,600 acfm	Dust collector	AQ0316CPT01
109	Ash Handling System	NA	TBD[8]	Particulate Matter	1.3 acfm	Dust collector	AQ0316CPT01
110	Ash Handling System Vacuum	NA	TBD[8]	Particulate Matter	400 acfm	Dust collector	AQ0316CPT01
111	Ash Loadout to truck	NA	TBD[8]	Particulate Matter	NA	NA	AQ0316CPT01
112	Cooling Tower	NA	TBD[8]	Particulate Matter	7,300 gal/min	NA	AQ0316CPT01

[8] EU IDs 101 through 112 are permitted under AQ0316CPT01 and are not yet installed or in service.
[9] Not applicable.

3. REFERENCES

ADEC, *Statement of Basis of the Terms and Conditions for Permit No. AQ0316TVP02, Revision 1, University of Alaska – Fairbanks Campus Power Plant,* December 4, 2007.

ADEC, *Technical Analysis Report for Permit No. AQ0316CPT01, University of Alaska Fairbanks Campus,* April 2, 2014.

U.S. EPA, Clean Air Act, http://www.epw.senate.gov/envlaws/cleanair.pdf, Accessed on June 23, 2015.

U.S. EPA, Federal Register, Vol. 61, No. 142, *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR); Proposed Rule,* 40 CFR Parts 51 and 52, July 23, 1996.

U.S. EPA, Federal Register, Vol. 74, No. 218, *Air Quality Designations for the 2006 24-Hour Fine Particle ($PM_{2.5}$) National Ambient Air Quality Standards*, *Final Rule*, 40 CFR Part 81, November 13, 2009.

US EPA, *EPA Air Pollution Cost Control Manual*, EPA-452/B-02-001, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., January 2002.

U.S. EPA, *New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting (Draft),* Office of Air Quality Planning and Standards, Research Triangle Park, N.C., October 1990.

U.S. EPA, WebFIRE, Technology Transfer Network Clearinghouse for Inventories and Emission Factors, http://cfpub.epa.gov/webfire, Accessed on June 18, 2015.

APPENDIX A

ADEC REQUEST FOR VOLUNTARY BACT ANALYSIS OF THE UAF CAMPUS

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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PO Box 111800
Juneau, Alaska 99811-1800
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CERTIFIED MAIL: 7014 0514 0001 9932 8897
Return Receipt Requested

April 24, 2015

Frances Isgrigg
Director of Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Voluntary BACT Analysis for Fairbanks Campus Power Plant

Dear Ms. Isgrigg:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

<u>Background</u>

EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98^{th} percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

• Serious Area SIP inventory development starts:	January, 2015
• BACT kick off meeting:	March 5, 2015
• Submit initial BACT results to ADEC:	December, 2015
• Submit complete/final BACT analysis to ADEC:	March, 2016
• Serious Area SIP modeling by ADEC starts:	March, 2016
• Serious Area designation by EPA (Expected):	June, 2016
• Serious Area SIP draft:	December, 2016
• Serious Area SIP public notice period:	February, 2017
• Serious Area SIP submitted by ADEC to EPA:	December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality

APPENDIX B

EXAMPLE ECONOMIC ANALYSIS TEMPLATES

Table B-1. Example Total Capital Investment Determination

Capital Costs		
DIRECT COSTS	**Cost Factors**	
(1) Purchased equipment and material costs		
(a) Basic equipment		=
(b) Instrumentation		=
(c) Freight		=
(d) Labor		=
(e) Startup Spares		=
(f) Vendor representatives fees		=
Purchased Equipment and Materials Cost (PEMC)		=
(2) Direct Installation Costs		
(a) Concrete		=
(b) Piling		=
(c) Structural steel		=
(d) Electrical		=
(e) Painting		=
(f) Insulation		=
(g) Abovegrade piping		=
(h) Functional Checkouts		=
Direct Installation Costs (DIC)		=
Total Direct Costs (TDC)	(PEMC) + (DIC)	=
INDIRECT COSTS		
(3) Engineering, Procurement & Construction Support Services		=
(4) Performance tests		=
Total Indirect Costs (TIC)		=
MANAGEMENT AND CONTINGENCY COSTS		
(5) UOC Costs		=
(6) Contingency		=
Total Management and Contingency Costs (TM&CC)		=
TOTAL CAPITAL INVESTMENT (TCI)	(TDC)+(TIC)+(TM&CC)	=

Table B-2. Example Cost Effectiveness Determination

Annualized Costs		
DIRECT ANNUAL COSTS	**Cost Factors**	
(1) Operating labor		=
(2) Supervisory labor		=
(3) Maintenance labor		=
(4) Maintenance materials		=
(5) Utilities		
Fuel:		=
Electricity:		=
Total Direct Annual Costs (TDAC)		=
INDIRECT ANNUAL COSTS		
(6) Overhead		=
(7) Administrative Charges		=
(8) Property tax		=
(9) Insurance		=
(10) Capital Recovery	(CRF*TCI)	=
Capital Recovery Factor (CRF) [7% ROR, 10-year life] is 0.1424		
Total Indirect Annual Costs (TIAC)		=
TOTAL ANNUALIZED COSTS (TAC)	**(TDAC) + (TIAC)**	=
Cost Effectiveness Summary		
TOTAL TONS AVOIDED PER YEAR		=
COST EFFECTIVENESS ($ PER TON AVOIDED)	**(TAC)/(TPY)**	=

THE STATE of ALASKA

GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
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August 14, 2015

Frances M. Isgrigg, Director
Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
1855 Marika Road
PO Box 758145
Fairbanks, AK 99775-8145

Subject: UAF PM2.5 Serious Nonattainment BACT Protocol Response

Dear Ms. Isgrigg:

Thank you for submitting your PM2.5 Serious Nonattainment BACT Analysis Protocol for the UAF Stationary Source.

The clarifications you have requested are below:

1. The stationary source modeling was completed for the Fairbanks PM2.5 Moderate Area SIP Submittal using the CALPLPUFF dispersion model with emissions and meteorology data representative of a severe PM2.5 winter episode. Emissions input were based on actual (reported) 2008 emissions for a two week representative metrological episode (January-February 2008). Meteorology inputs were simulated with the WRF (Weather Research and Forecast) meteorological model (Linux system required) and processed through the MMIF (Mesoscale Model Interface) preprocessor model. The modeling files are approximately 1TB in size. DEC can provide the modeling files if you can make an external hard drive available.
2. The baseline year modeling for the Serious Area will be one of the last three years of the design value that caused the Fairbanks area to become a Serious Area: 2013, 2014 or 2015.
3. The EPA R10 has provided informal comments on the BACT protocol that was submitted and they are below.

    a. The BACT analysis should be conducted for the proposed boilers (EU IDs 101 and 102). Before the BACT analysis is officially submitted with the Serious Area SIP, a permit change is required that states if the proposed boilers are not completed by the required completion date (four years after the official designation expected in 2016), a BACT analysis will need to be completed on the old boilers.

Clean Air

b. A Serious Area BACT analysis is only required for permitted emission units.
c. EPA Region 10 reviewed the protocol and made comments, but they will not give full approval of the BACT analysis until it has been officially submitted by DEC (see the excerpt from an email below).

USEPA Region 10 Response to the PM2.5 Serious Nonattainment BACT Analysis Protocol for the UAF Stationary Source:

"EPA is providing informal comments to you on the BACT protocol provided by the University of Alaska, Fairbanks. At this time, we are not approving the protocol –we will formally review and approve the BACT analysis if/when it is submitted to us as part of the Serious Area Attainment Plan.

As we discussed earlier, it is important to clarify to UAF that, if there is any delay in the boiler replacement project and schedule, UAF will need to conduct a BACT analysis for the existing boilers. And, we understand that you have had discussions with UAF about this already, and that you are planning to ensure that UAF will take steps to address this through updates to the facilities' existing permit(s).

Below are some additional comments on the protocol document

BACT Protocol

1. *Section 1 – The BACT analysis will be evaluated with respect to EPA BACT guidance. The protocol needs to be consistent with that guidance - this protocol will not govern should any inconsistency be identified.*
2. *Section 1.5 – This section should clarify that all cost analyses will be conducted in accordance with the EPA Air Pollution Control Cost Manual.*
3. *Section 1.5 – The final sentence should be modified as follows "…if a particular control technology is eliminated based on economic factors, the assumption will be made that the control technology is also uneconomic for smaller emission units, provided that all other factors besides size are equivalent." This clarification is necessary because the reasoning only applies for emission units that are the same basic type of equipment, burn the same fuel, have similar retrofit challenges, etc.*
4. *Section 1.6 – Cost information must be emission unit specific. BACT cannot be determined using generic cost ranges.*
5. *Section 1.6 – Each BACT analysis must provide the basis for each input value and assumption used in the analysis and calculations. Electronic (pdf) copies of the actual documents forming the basis for each assumption should be provided. If the documents are publicly available on the internet, functional links to the information is acceptable.*
6. *Section 2 – The BACT analyses need to be conducted based on potential to emit (PTE), and EPA will verify the basis for the PTE values used for each emission unit and each pollutant. The BACT analysis should provide the basis and actual calculations used to derive each PTE value. It is acceptable to cite another document that forms the basis for the PTE, but these underlying documents must be included as attachments to the BACT analysis, and must themselves include sufficient detail in order to clearly illustrate the basis for the PTE values.*
7. *Table 2 – No control for particulate matter is listed for the proposed new boilers, although presumably they will be equipped with such control equipment."*

Thank you again for submitting your BACT protocol for DEC and EPA Review.
If you have any further questions in order to complete a timely BACT analysis, please contact me.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Cindy Heil, ADEC/Non-Point Mobile Sources
Patrick Dunn, ADEC/Air Permits Program
Deanna Huff, ADEC/Non-Point Mobile Sources

Voluntary Best Available Control Technology Analysis

for the:

Serious $PM_{2.5}$ Non-Attainment Area Classification

prepared for:

University of Alaska Fairbanks

prepared by:

January 2017

Executive Summary

UAF prepared this voluntary Best Available Control Technology (BACT) analysis for equipment expected to be operating on campus by 2019 in anticipation that the U. S. Environmental Protection Agency (EPA) will re-classify the Fairbanks $PM_{2.5}$ Non-attainment area (NAA) as a 'serious' NAA. The UAF campus is a major source of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) emissions which triggers BACT review because these pollutants are precursors to particulate matter. Although the UAF $PM_{2.5}$ emissions are below the threshold for being a major source contributing impact to the NAA, UAF has proactively conducted a BACT analysis of the $PM_{2.5}$ emissions should the information be useful.

The equipment at the UAF campus that contributes to impacts in the $PM_{2.5}$ NAA include the two large diesel-fired boilers (EU IDs 3 and 4), one large peaking/backup generator engine (EU ID 8), a pathological waste incinerator (EU ID 9A), three diesel-fired boilers (EU IDs 19 through 21), one diesel-fired generator (EU ID 27), nine material handling systems (EU IDs 105, 107, 109 through 111, 114, and 128 through 130), and one large coal-fired CFB boiler (EU ID 113).

UAF reviewed the NO_X emission control options and has determined that the current equipment designs and controls in place are BACT. Permit No. AQ0316MSS06 Revision 1 authorizes construction of EU ID 113, a coal-fired, circulating fluidized bed (CFB) boiler. CFB with staged combustion is proposed as NO_X BACT for EU ID 113.

The $PM_{2.5}$ review concluded that the existing emission control options are BACT for the permitted equipment. Of the new equipment authorized in Permit No. AQ0316MSS06 Revision 1, fabric filters will be included on the large CFB boiler (EU ID 113) and many of the material handling emission units (EU IDs 105, 17, 109, 110, 114, and 128 through 130). Material handling unit EU ID 111 is the ash loadout transfer point for which a fabric filter is not technically feasible, so $PM_{2.5}$ BACT for EU ID 111 is use of the enclosure.

UAF is proposing to switch all remaining diesel-fired units (EU IDs 3, 4, and 8) to ultra-low sulfur diesel (ULSD) combustion to reduce SO_2 emissions as SO_2 BACT. This change results in a potential SO_2 emission reduction of up to 489 tpy of SO_2. This reduction does not take credit for the three boilers that already fire ULSD or the sulfur reduction achieved by using limestone injection with low sulfur fuel as part of the proposed CFB boiler design and operation. No new emission control options are proposed as SO_2 BACT for the non-diesel-fired units.

A summary of the BACT determinations for all three pollutants is provided in Table ES-1.

Table ES-1. Summary of Proposed BACT Determinations for Equipment at the University of Alaska Fairbanks Campus

Emission Unit		Proposed BACT Determination[1]		
ID	**Description**	**NO_X**	**$PM_{2.5}$**	**SO_2**
3	Mid-sized Boiler	Good Combustion Practices	Good Combustion Practices	**ULSD**
4	Mid-sized Boiler	Limited Operation	Limited Operation	**ULSD** + Limited Operation
8	Large Engine	Turbocharger and Aftercooler + Limited Operation	Positive Crankcase Ventilation + Low Ash Fuel + Limited Operation	**ULSD** + Limited Operation
9A	Medical/Pathological Waste Incinerator	Good Combustion Practices + Limited Operation	Multiple Chambers + Limited Operation	**ULSD** + Limited Operation
19	Small Boiler	Limited Operation	Limited Operation	ULSD
20	Small Boiler			
21	Small Boiler			
27	Small Engine	Turbocharger and Aftercooler + Federal Limit + Limited Operating	Federal Limit (NSPS Subpart IIII, Tier 3) + Limited Operation	ULSD
105	Limestone Handling System	N/A	Fabric Filter + Enclosure	N/A
107	Sand Handling System	N/A	Fabric Filter + Enclosure	N/A
109	Ash Handling System	N/A	Fabric Filter + Enclosure	N/A
110	Ash Handling System Vacuum	N/A	Fabric Filter + Enclosure	N/A
111	Ash Loadout to Truck	N/A	Enclosure	N/A
113	Large Boiler	CFB with staged combustion	Fabric Filter	Limestone Injection + Low Sulfur Fuel
114	Dry Sorbent Handling Vent Filter Exhaust	N/A	Fabric Filter + Enclosure	N/A
128	Coal Silo No. 1 with bin vent	N/A	Fabric Filter + Enclosure	N/A
129	Coal Silo No. 2 with bin vent	N/A	Fabric Filter + Enclosure	N/A
130	Coal Silo No. 3 with bin vent	N/A	Fabric Filter + Enclosure	N/A

Notes:

[1] Determinations in **bold** are changes to the required controls in the applicable operating permit or minor permit.

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ACRONYMS

ADEC	Alaska Department of Environmental Conservation
A/F	Air to Fuel
BACT	Best Available Control Technology
CFB	Circulating Fluidized Bed
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DEF	Diesel Exhaust Fluid
dscf	Dry Standard Cubic Feet
DPF	Diesel Particulate Filter
DSI	Dry Sorbent Injection
ESP	Electrostatic Precipitator
EPA	U.S. Environmental Protection Agency
EU	Emission Unit
EU ID	Emission Unit Identification
EUAC	Equivalent Uniform Annual Cost
F	Fahrenheit
FGD	Flue Gas Desulfurization
FGR	Flue Gas Reduction
FITR	Fuel Injection Timing Retard
gr	Grains
g/kWh	Grams Per Kilowatt- Hour
H_2	Hydrogen
HC	Hydrocarbons
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid
hp	Horsepower
ID	Identification
ITR	Ignition Timing Retard
LAER	Lowest Achievable Emission Rate
LNB	Low NO_X Burner
MACT	Maximum Achievable Control Technology

ACRONYMS (Continued)

MMBtu/hr	Million British Thermal Units per Hour
NAA	Nonattainment Area
NH_3	Ammonia
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NO_X	Total Nitrogen Oxides
NRE	Non-road Engine
NSCR	Non Selective Catalytic Reduction
NSPS	New Source Performance Standards
NSR	New Source Review
OFA	Overfired Air
PC	Pulverized Coal
PM	Particulate matter
$PM_{2.5}$	Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	Parts per Million
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SCI	Stanley Consultants, Inc.
SCR	Selective Catalytic Reduction
SDA	Spray Dry Absorber
SNCR	Selective Non Catalytic Reduction
SLR	SLR International Corporation
SO_2	Sulfur Dioxide
tpy	Tons per Year
UAF	University of Alaska Fairbanks
ULSD	Ultra-low Sulfur Diesel
VOC	Volatile Organic Compounds

1.0 Introduction

The Alaska Department of Environmental Conservation (ADEC) has requested that certain stationary sources in the Fairbanks particulate matter with an aerodynamic less than or equal to a nominal 2.5 microns ($PM_{2.5}$) nonattainment area voluntarily prepare a Best Available Control Technology (BACT) analysis. This request was issued in anticipation of the $PM_{2.5}$ nonattainment area (NAA) being re-classified by the U.S. Environmental Protection Agency (EPA) as "serious" in 2016. The University of Alaska Fairbanks (UAF) is one of many sources of $PM_{2.5}$ emissions located within the Fairbanks $PM_{2.5}$ nonattainment area.

This BACT analysis has been prepared for all permitted stationary emission units at the facility that are expected to be installed and operating by 2019, have emissions of direct $PM_{2.5}$ or a precursor, and have a combined potential to emit (PTE) of 70 tons per year (tpy), on a pollutant-by-pollutant basis. In a serious $PM_{2.5}$ nonattainment area, 70 tpy is the major stationary source threshold. The precursors to $PM_{2.5}$ include nitrogen oxides (NO_X), sulfur dioxide (SO_2), volatile organic compounds (VOC), and ammonia (NH_3). As shown in Table 1-1, potential emissions of NO_X and SO_2 exceed the 70 tpy threshold, are $PM_{2.5}$ precursors, and so will be reviewed. Although the $PM_{2.5}$ PTE is less than the 70 tpy BACT review threshold requirement, UAF is proactively including $PM_{2.5}$ in this BACT analysis.

Table 1-1. UAF Serious Nonattainment Area Major Source Applicability

Pollutant	Potential to Emit[1] (tpy)	Major Source? >70 tpy PTE
NO_X	454	Yes
$PM_{2.5}$	42	No
SO_2	710	Yes
VOC	23	No
NH_3	<1	No

[1] NO_X, $PM_{2.5}$, and SO_2 PTE are from Table 1-2. VOC and NH_3 PTE are from the *$PM_{2.5}$ Serious Nonattainment Area BACT Analysis Protocol for the UAF Campus Stationary Sources,* dated July 2015.

This BACT analysis has been prepared according to the BACT analysis protocol submitted to ADEC on July 23, 2015, and incorporates the ADEC comments received on August 10, 2015. As approved in the ADEC comments, emission units at the facility that are planned for removal no later than 2019 are not included in this BACT analysis. New emission units that are planned for permitting and installation by 2019 are included in this analysis.

This $PM_{2.5}$ serious NAA BACT analysis includes NO_X, $PM_{2.5}$, and SO_2 emissions from the significant emission units that are expected to be installed and operating in 2019. The emission units included in this analysis are:

- Emission Unit Identification (EU ID) 113, a large coal and biomass-fired boiler;
- EU IDs 3 and 4, the existing mid-sized diesel-fired and dual fuel-fired (diesel and natural gas-fired) boilers, respectively;
- EU IDs 19, 20, and 21, the existing small diesel-fired boilers;
- EU ID 8, an existing large diesel-fired engine;
- EU ID 27, a small diesel-fired engine;
- EU ID 9A, the pathological waste incinerator; and
- EU IDs 105, 107, 109 through 111, 114, and 128 through 130, material handling systems.

As shown in Table 1-2, EU IDs 105, 107, 109 through 111, 114, and 128 through 130 do not emit NO_X or SO_2 and are not included in those respective BACT analyses. Tables 1-3, 1-4, and 1-5 provide detailed worst-case PTE calculations for each emission unit for NO_X, $PM_{2.5}$, and SO_2, respectively.

Table 1-2. Potential to Emit Inventory for BACT Basis of Worst-Case Emissions - Significant Emission Units
University of Alaska Fairbanks Campus

Emission Unit				Installation	Fuel Type	Maximum	Maximum Operation	Potential Emissions (tpy)		
ID	Description	Make/Model	Bldg. No.	Date		Rating/Capacity		NO_X	$PM_{2.5}$	SO_2
3	Dual-Fired Boiler	Zurn	FS802	1970	Diesel[1]	180.9 MMBtu/hr	8,760 hr/yr	138.8	12.3	410.6
4	Dual-Fired Boiler	Zurn	FS802	1987	Duel - Diesel and NG	180.9 MMBtu/hr[2]	158,468 MMBtu/yr[2]	13.9	1.2	40.0
							8,760 hr/yr[2]	11.1	0.6	0.048
8	Peaking/Backup Generator (DEG) Engine	Fairbanks Morse Colt-Pielstick PC2.6	FS817	1999	Diesel[3]	13,266 hp	8,760 hr/yr	40.0	1.0	40.0
9A	BiRD - Medical/Pathological Waste Incinerator	Therm-Tec/G-30P-1H	FS919	2006	Medical/Pathological Waste[4]	83 lb/hr[5]	109 tpy[6]	0.2	0.3	0.1
19	BiRD RM 100U3 Boiler No. 1	Weil McLain/2094W	FS919	2004	ULSD[7]	6.13 MMBtu/hr[8]	19,650 hr/yr[9]	8.8	0.9	0.1
20	BiRD RM 100U3 Boiler No. 2	Weil McLain/2094W	FS919	2004	ULSD[7]	6.13 MMBtu/hr[8]				
21	BiRD RM 100U3 Boiler No. 3	Weil McLain/2094W	FS919	2004	ULSD[7]	6.13 MMBtu/hr[8]				
27	Alaska Center for Energy and Power Generator Engine	Caterpillar C-15 (Tier 3)	FS814	June 2012	ULSD	500 hp	4,380 hr/yr[10]	7.7	0.3	1.2E-02
105	Limestone Handling System	TBD	TBD	TBD	N/A	1,200 acfm	8,760 hr/yr	N/A	0.1	N/A
107	Sand Handling System	TBD	TBD	TBD	N/A	1,600 acfm	8,760 hr/yr	N/A	0.2	N/A
109	Ash Handling System	TBD	TBD	TBD	N/A	1,000 acfm	8,760 hr/yr	N/A	0.1	N/A
110	Ash Handling System Vacuum	TBD	TBD	TBD	N/A	2,000 acfm	8,760 hr/yr	N/A	0.2	N/A
111	Ash Loadout to Truck	TBD	TBD	TBD	N/A	N/A	26,280 tpy	N/A	7.2E-04	N/A
113	Replacement Dual-fired CFB Boiler	Babcock & Wilcox	TBD	TBD	Coal/Woody Biomass	295.6 MMBtu/hr	8,760 hr/yr	258.9	15.5	258.9
114	Dry Sorbent Handling Vent Filter Exhaust	TBD	TBD	TBD	N/A	5 acfm	8,760 hr/yr	N/A	9.4E-03	N/A
128	Coal Silo No. 1 with bin vent	TBD	TBD	TBD	N/A	1,650 acfm	8,760 hr/yr	N/A	0.2	N/A
129	Coal Silo No. 2 with bin vent	TBD	TBD	TBD	N/A	1,650 acfm	8,760 hr/yr	N/A	0.2	N/A
130	Coal Silo No. 3 with bin vent	TBD	TBD	TBD	N/A	1,650 acfm	8,760 hr/yr	N/A	0.2	N/A
							Total[11]	454.4	33.3	709.8

Notes:

[1] Although this boiler is permitted as a dual fuel-fired boiler, the unit is configured to fire only diesel. A BACT analysis will only be completed for diese firing for this unit.

[2] EU ID 4 has a 10 percent capacity factor limit and a 158,468 MMBtu/yr limit per Condition 17 of Permit No. AQ0316TVP02, Rev 1.

[3] EU ID 8 is also authorized to combust coal slurry fuel. The unit has not operated on this fuel and will not do so in the future. Emission estimates fo this unit are based on diesel fuel combustion.

[4] EU ID 9A fuel is piped with EU IDs 19 through 21. Because EU IDs 19 through 21 are required to use ULSD, EU ID 9A is also firing ULSD.

[5] The rating of EU ID 9A is listed incorrectly in the existing Title V permit. The correct rating provided here is from the Title V permit renewal application.

[6] EU ID 9A is limited by Condition 8 of Permit No. AQ0316MSS04 to 109 tons of waste combustion per rolling 12-month period.

[7] EU IDs 19 through 21 are limited to operating on ULSD per Condition 9 of Permit No. AQ316MSS04.

[8] The nameplates for EU IDs 19 through 21 list the ratings in gross output or do not specify whether the rating is output or input. A 75 percent efficiency has been assumed for these units to conservatively calculate the heat input rating per the Title V permit renewal application.

[9] EU IDs 19 through 21 are limited to operating no more than 19,650 hr/yr, combined, per Condition 10 of Permit No. AQ0316MSS04.

[10] EU ID 27 is limited to operating no more than 4,380 hr/yr per Condition 4 of Permit No. AQ0316MSS03.

[11] The total emissions for NO_X and SO_2 are restricted for EU IDs 4 and 8 to 40 tpy for each pollutant because the units share these limits for both pollutants. Emission for $PM_{2.5}$ is the sum of all emissions from all units.

Table 1-3. Potential to Emit Calculations for BACT Basis of Worst-Case Emissions - NO_X Emissions
University of Alaska Fairbanks Campus

Emission Unit		Fuel Type	NO_X Emission Factor		Maximum Rating/Capacity	Allowable Annual Operation[1]	Control Technology	Technology Efficiency	Short Term NO_X Emissions	Potential NO_X Emissions[2]
ID	Description		Reference	Factor						
Significant Emission Units										
3	Dual-Fired Boiler	Diesel	AP-42 Table 1.3-1	24 lb/kgal	180.9 MMBtu/hr	8,760 hr/yr	Standard Combustor when firing Diesel		0.175 lb/MMBtu	138.8 tpy[3]
4	Dual-Fired Boiler	Diesel	AP-42 Table 1.3-1	24 lb/kgal	180.9 MMBtu/hr	158,468 MMBtu/yr	Standard Combustor when firing Diesel + 10 Percent Capacity Factor	90%	0.175 lb/MMBtu	13.9 tpy[4]
4	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-1 low NO_X	140 lb/MMscf	180.9 MMBtu/hr	8,760 hr/yr	Low NOx Burners + 10 Percent Capacity Factor	90%	140.0 lb/MMscf	11.1 tpy[4]
8	Peaking/Backup Generator (DEG) Engine	Diesel	AQ0316MSS02, Cond.12.3b	0.571 lb/gal	13,266 hp	140,105 gal/yr[5]	Turbocharging and Intercooler		0.0195 g/hp-hr	40.0 tpy[5]
9A	BiRD - Medical/Pathological Waste Incinerator	Medical/Pathological Waste	AP-42 Table 2.3-1	3.56 lb/ton	83 lb/hr	109 ton/yr[6]	Multi-chamber (4 primary burners and 2 flue duct burners)		3.56 lb/ton	0.2 tpy
19	BiRD RM 100U3 Boiler No. 1	ULSD[7]	AP-42 Table 1.3-1	20 lb/kgal	6.13 MMBtu/hr		N/A		1.24 g/MMBtu	
20	BiRD RM 100U3 Boiler No. 2	ULSD[7]	AP-42 Table 1.3-1	20 lb/kgal	6.13 MMBtu/hr	19,650 hr/yr[8]	N/A		1.24 g/MMBtu	8.8 tpy
21	BiRD RM 100U3 Boiler No. 3	ULSD[7]	AP-42 Table 1.3-1	20 lb/kgal	6.13 MMBtu/hr		N/A		1.24 g/MMBtu	
27	Alaska Center for Energy and Power Generator Engine	ULSD	Vendor Data	3.52 lb/hr	500 hp	4,380 hr/yr[9]	Tier 3, Turbocharger and aftercooler		3.20 g/hp-hr	7.7 tpy
105	Limestone Handling System	N/A		N/A	1,200 acfm	8,760 hr/yr	N/A			N/A
107	Sand Handling System	N/A		N/A	1,600 acfm	8,760 hr/yr	N/A			N/A
109	Ash Handling System	N/A		N/A	1,000 acfm	8,760 hr/yr	N/A			N/A
110	Ash Handling System Vacuum	N/A		N/A	2,000 acfm	8,760 hr/yr	N/A			N/A
111	Ash Loadout to Truck	N/A		N/A	N/A	26,280 tpy	N/A			N/A
113	Replacement Dual-fired CFB Boiler	Coal/Woody Biomass	40 CFR 60.44b(l)(1)	0.20 lb/MMBtu heat input	296 MMBtu/hr	8,760 hr/yr	N/A		0.20 lb/MMBtu heat input	259 tpy
114	Dry Sorbent Handling Vent Filter Exhaust	N/A		N/A	5 acfm	8,760 hr/yr	N/A			N/A
128	Coal Silo No. 1 with bin vent	N/A		N/A	1,650 acfm	8,760 hr/yr	N/A			N/A
129	Coal Silo No. 2 with bin vent	N/A		N/A	1,650 acfm	8,760 hr/yr	N/A			N/A
130	Coal Silo No. 3 with bin vent	N/A		N/A	1,650 acfm	8,760 hr/yr	N/A			N/A

Notes:

1 Maximum annual operation for all units based on full-time operation, or permitted operating limits, where applicable.

2 Conversion factors:

Mass Conversion	454.0	g/lb
Diesel Heating Value	0.137	MMBtu/gal
Natural Gas Heat Content	1,000	Btu/scf

3 Although this boiler is permitted as a dual fuel-fired boiler, the unit is configured to fire only diesel. The potential NO_X emissions for EU ID 3 are based on diesel fuel combustion.

4 Maximum annual operation of EU ID 4 while firing diesel or gas is restricted by a 10 percent capacity factor limit on the annual the heat input, and by a limit that restrict emissions to less the 40 tpy for EU ID and EU ID 8, combined per Condition 16 of Operating Permit AQ0316TVP02.

5 Maximum annual operation of EU ID 8 is restricted by the 40 tpy of NO_X emission limit that is shared with EU ID 4. EU ID 8 can consume no more than 140,105 gal/year of fuel and be in compliance this limit. (40 ton/yr * 2,000 lb/ton/0.571 lb/gal = 140,105 gal/yr)

6 EU ID 9A is limited by Condition 8 of Permit No. AQ0316MSS04 to 109 tons of waste combustion per rolling 12-month.

7 EU IDs 19 through 21 are limited to operating on ULSD per Condition 9 of Permit No. AQ316MSS04.

8 EU IDs 19 through 21 are limited to operate no more than 19,650 hr/yr, combined, per Condition 10 of Permit No. AQ0316MSS04.

9 EU ID 27 limited to operating no more than 4,380 hr/yr per Condition 4 of Permit No. AQ0316MSS03.

Table 1-4. Potential to Emit Calculations for BACT Basis of Worst-Case Emissions - $PM_{2.5}$ Emissions
University of Alaska Fairbanks Campus

Emission Unit ID	Emission Unit Description	Fuel Type	$PM_{2.5}$ Emission Factor Reference	$PM_{2.5}$ Emission Factor Factor	Maximum Rating/Capacity	Allowable Annual Operation[1]	Control Technology	Technology Efficiency	Short Term $PM_{2.5}$ Emissions	Potential $PM_{2.5}$ Emissions[2]
Significant Emission Units										
3	Dual-Fired Boiler	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	180.9 MMBtu/hr	8,760 hr/yr	N/A		0.016 lb/MMBtu	12.3 tpy[3]
4	Dual-Fired Boiler	Diesel	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	180.9 MMBtu/hr	158,468 MMBtu/yr	Standard Combustor when firing Diesel + 10 Percent Capacity Factor	90%	0.016 lb/MMBtu	1.2 tpy[4]
4	Dual-Fired Boiler	Natural Gas	AP-42 Table 1.4-2	7.6 lb/MMscf	180.9 MMBtu/hr	8,760 hr/yr	Low NOx Burners + 10 Percent Capacity Factor	90%	7.6 lb/MMscf	0.6 tpy[4]
8	Peaking/Backup Generator (DEG) Engine	Diesel	AP-42 Table 3.4-1	0.1 lb/MMBtu	13,266 hp	140,105 gal/yr	Positive Crankcase Ventilation		0.10 lb/MMBtu	1.0 tpy[5]
9A	BiRD - Medical/Pathological Waste Incinerator	Medical/Pathological Waste	AP-42 Table 2.3-2	4.67 lb/ton	83 lb/hr	109 ton/yr[6]	Multi-chamber (4 primary burners and 2 flue duct burners)		4.67 lb/ton	0.25 tpy
19	BiRD RM 100U3 Boiler No. 1	ULSD[7]	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	6.13 MMBtu/hr	19,650 hr/yr[8]	N/A		7.06 g/MMBtu	0.94 tpy
20	BiRD RM 100U3 Boiler No. 2	ULSD[7]	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	6.13 MMBtu/hr		N/A		7.06 g/MMBtu	
21	BiRD RM 100U3 Boiler No. 3	ULSD[7]	AP-42 Tables 1.3-2, 1.3-7	2.13 lb/kgal	6.13 MMBtu/hr		N/A		7.06 g/MMBtu	
27	Alaska Center for Energy and Power Generator Engine	ULSD	Vendor Data	0.12 lb/hr	500 hp	4,380 hr/yr[9]	Tier 3		0.11 g/hp-hr	0.263 tpy
105	Limestone Handling System	N/A	Design Specifications	0.003 gr/dcf	1,200 acfm	8,760 hr/yr	Dust Collector		0.003 gr/dcf	0.14 tpy
107	Sand Handling System	N/A	Design Specifications	0.003 gr/dcf	1,600 acfm	8,760 hr/yr	Dust Collector		0.003 gr/dcf	0.18 tpy
109	Ash Handling System	N/A	Design Specifications	0.003 gr/dcf	1,000 acfm	8,760 hr/yr	Dust Collector		0.003 gr/dcf	1.1E-01 tpy
110	Ash Handling System Vacuum	N/A	Design Specifications	0.003 gr/dcf	2,000 acfm	8,760 hr/yr	Dust Collector		0.003 gr/dcf	0.23 tpy
111	Ash Loadout to Truck	N/A	AP-42 Table 13.2.4	5.50E-05 lb/ton[10]	N/A	26,280 tpy	Enclosure		5.50E-05 lb/ton	7.23E-04 tpy
113	Replacement Dual-fired CFB Boiler	Coal/Woody Biomass	Vendor Data	0.012 lb/MMBtu	296 MMBtu/hr	8,760 hr/yr	Baghouse		0.012 lb/MMBtu	15.5 tpy
114	Dry Sorbent Handling Vent Filter Exhaust	N/A	AK state SIP PM emission std.	0.05 gr/dcf	5 acfm	8,760 hr/yr	Dust Collector		0.050 gr/dcf	9.4E-03 tpy
128	Coal Silo No. 1 with bin vent	N/A	Design Specifications	0.003 gr/dcf	1,650 acfm	8,760 hr/yr	Dust Collector		0.003 gr/dcf	0.19 tpy
129	Coal Silo No. 2 with bin vent	N/A	Design Specifications	0.003 gr/dcf	1,650 acfm	8,760 hr/yr	Dust Collector		0.003 gr/dcf	0.19 tpy
130	Coal Silo No. 3 with bin vent	N/A	Design Specifications	0.003 gr/dcf	1,650 acfm	8,760 hr/yr	Dust Collector		0.003 gr/dcf	0.19 tpy

Notes:

[1] Maximum annual operation for all units based on full-time operation, or permitted operating limits, where applicable.

[2] Conversion factors:

Mass Conversion	454.0 g/lb
Diesel Heating Value	0.137 MMBtu/gal
Mass Conversion	7,000 gr/lb
Natural Gas Heat Content	1,000 Btu/scf
Engine Heat Rate	7,000 Btu/hp-hr

[3] Although this boiler is permitted as a dual fuel-fired boiler, the unit is configured to fire only diesel. The potential $PM_{2.5}$ emissions for EU ID 3 are based on diesel fuel combustion.

[4] Maximum annual operation of EU ID 4 while firing diesel or gas is limited by the 10 percent annual capacity factor which restricts the heat input.

[5] The highest potential $PM_{2.5}$ emissions for EU ID 8 is shown using the NO_X-driven fuel restriction.

[6] EU ID 9A is limited by Condition 8 of Permit No. AQ0316MSS04 to 109 tons of waste combustion per rolling 12-month.

[7] EU IDs 19 through 21 are limited to operating on ULSD per Condition 9 of Permit No. AQ316MSS04.

[8] EU IDs 19 through 21 are limited to operating no more than 19,650 hr/yr, combined, per Condition 10 of Permit No. AQ0316MSS04.

[9] EU ID 27 limited to operating no more than 4,380 hr/yr per Condition 4 of Permit No. AQ0316MSS03.

[10] Ash loadout emission calculations:

Emission factor from AP-42, Section 13.2.4 based on empirical equation $E = k \times 0.0032 \times (U/5)^{1.3}/(M/2)^{1.4}$ lb/ton transferred where:

k for $PM_{2.5}$ = 0.053

U = mean wind speed = 5.4 mph in Fairbanks, per National Climactic Data Center (http://lwf.ncdc.noaa.gov/oa/climate/online/ccd/avgwind.html)

M = ash moisture content = 4.8 percent (AP-42, page 13.2.4-4)

Ash loadout emissions based on maximum boiler total coal consumption capacity 26,280 tpy

Ash content of coal = 8.5% per Usibelli Coal Mine website

Operations, ash tons/hr = (Σ coal capacity, ton/hr) x (0.085 ash content) + (captured sulfur, captured oxygen, and limestone inerts) = 3 ton/hr per design engineers

Operations, ash tons/yr = (3 ton/hr) * (8,760 hr/yr)

Ash loadout emissions, tons/yr = (emission factor, lb/ton) x (ash loading, ton/yr) / (2,000 lb/ton)

Table 1-5. Potential to Emit Calculations for BACT Basis of Worst-Case Emissions - SO_2 Emissions
University of Alaska Fairbanks Campus

Emission Unit ID	Emission Unit Description	Fuel Type	Fuel Sulfur Content	SO_2 Emission Factor Reference	SO_2 Emission Factor Factor	Maximum Rating/Capacity	Allowable Annual Operation[1]	Control Technology	Technology Efficiency	Short Term SO_2 Emissions	Potential SO_2 Emissions[2]
Significant Emission Units											
3	Dual-Fired Boiler	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	180.9 MMBtu/hr	8,760 hr/yr	N/A		0.52 lb/MMBtu	410.6 tpy[3]
4	Dual-Fired Boiler	Diesel	0.5 weight %	AP-42 Table 1.3-1	142 *S lb/kgal	180.9 MMBtu/hr	154,366 MMBtu/yr[4]	Standard Combustor when firing Diesel + 10 Percent Capacity Factor	90%	0.52 lb/MMBtu	40.0 tpy[4]
4	Dual-Fired Boiler	Natural Gas	N/A	AP-42 Table 1.4-2	0.6 lb/MMscf	180.9 MMBtu/hr	8,760 hr/yr	Low NOx Burners + 10 Percent Capacity Factor	90%	0.60 lb/MMscf	0.0475 tpy[4]
8	Peaking/Backup Generator (DEG) Engine	Diesel	0.5 weight %	AP-42 Table 3.4-1	8.09E-03 *S lb/hp-hr	13,266 hp	1,010,529 galyr[5]	N/A		1.84 g/hp-hr	40.0 tpy
9A	BiRD - Medical/Pathological Waste Incinerator	Medical/Pathological Waste	N/A	AP-42 Table 2.3-1	2.17 lb/ton	83 lb/hr	109 tpy[6]	N/A		2.17 lb/ton	0.1 tpy
19	BiRD RM 100U3 Boiler No. 1	ULSD	0.0015 weight %[7]	AP-42 Table 1.3-1	142 *S lb/kgal	6.13 MMBtu/hr	19,650 hr/yr[8]	ULSD		0.013 g/MMBtu	0.094 tpy
20	BiRD RM 100U3 Boiler No. 2	ULSD	0.0015 weight %[7]	AP-42 Table 1.3-1	142 *S lb/kgal	6.13 MMBtu/hr		ULSD		0.013 g/MMBtu	
21	BiRD RM 100U3 Boiler No. 3	ULSD	0.0015 weight %[7]	AP-42 Table 1.3-1	142 *S lb/kgal	6.13 MMBtu/hr		ULSD		0.013 g/MMBtu	
27	Alaska Center for Energy and Power Generator Engine	ULSD	0.0015 weight %	Mass Balance	1.088E-05 lb/hp-hr	500 hp	4,380 hr/yr[9]	ULSD		0.005 g/hp-hr	0.01 tpy
105	Limestone Handling System	N/A	N/A	N/A	N/A	1,200 acfm	8,760 hr/yr	N/A		N/A	N/A
107	Sand Handling System	N/A	N/A	N/A	N/A	1,600 acfm	8,760 hr/yr	N/A		N/A	N/A
109	Ash Handling System	N/A	N/A	N/A	N/A	1,000 acfm	8,760 hr/yr	N/A		N/A	N/A
110	Ash Handling System Vacuum	N/A	N/A	N/A	N/A	2000 acfm	8,760 hr/yr	N/A		N/A	N/A
111	Ash Loadout to Truck	N/A	N/A	N/A	N/A	N/A	26,280 tpy	N/A		N/A	N/A
113	Replacement Dual-fired CFB Boiler	Coal/Woody Biomass	N/A	40 CFR 60.42b(k)(1)	0.20 lb/MMBtu heat input	296 MMBtu/hr	8,760 hr/yr	Limestone Injection, Low sulfur coal		0.20 lb/MMBtu	258.9 tpy
114	Dry Sorbent Handling Vent Filter Exhaust	N/A	N/A	N/A	N/A	5 acfm	8,760 hr/yr	N/A		N/A	N/A
128	Coal Silo No. 1 with bin vent	N/A	N/A	N/A	N/A	1650 acfm	8,760 tpy	N/A		N/A	N/A
129	Coal Silo No. 2 with bin vent	N/A	N/A	N/A	N/A	1650 acfm	8,760 hr/yr	N/A		N/A	N/A
130	Coal Silo No. 3 with bin vent	N/A	N/A	N/A	N/A	1,650 acfm	8,760 hr/yr	N/A		N/A	N/A

Notes:

[1] Maximum annual operation for all units based on full-time operation, or permitted operating limits, where applicable.

[2] Conversion factors:

Mass Conversion	454.0 g/lb
Diesel Heating Value	0.137 MMBtu/gal
Natural Gas Heat Content	1,000 Btu/scf
Density of Diesel	7.1 lb/gal
Engine Heat Rate	7,000 Btu/hp-hr

[3] Although this boiler is permitted as a dual fuel-fired boiler, the unit is configured to fire only diesel. The potential SO_2 emissions for EU ID 3 are based on diesel fuel combustion.

[4] Maximum annual operation of EU ID 4 while firing diesel is limited to 40 tpy of SO_2, a shared limit with EU ID 8. EU ID 4 can consume no more than 154,366 MMBtu/year and be in compliance with the 40 tpy limit. (40 ton/yr * 2,000 lb/ton /(0.52 lb/MMBtu) = 154,366 MMBtu/yr. Firing on natural gas is restricted by a 10 percent annual capacity factor.

[5] Maximum annual operation of EU ID 8 is limited to 40 tpy of SO_2, a limit shared with EU ID 4. EU ID 8 can consume no more than 1,010,529 gal/year and be in compliance with the 40 tpy limit. (40 ton/yr * 2,000 lb/ton /(8.09e-3 lb/hp-hr * 0.5%S) * 7,000 Btu/hp-hr * 1 MMBtu/10^6 Btu / 0.137 MMBtu/gal = 1,010,529 gal/yr)

[6] EU ID 9A is limited by Condition 8 of Permit No. AQ0316MSS04 to 109 tons of waste combustion per rolling 12-month period.

[7] EU IDs 19 through 21 are limited to operating on ULSD per Condition 9 of Permit No. AQ316MSS04.

[8] EU IDs 19 through 21 are limited to operating no more than 19,650 hr/yr, combined, per Condition 10 of Permit No. AQ0316MSS04.

[9] EU ID 27 limited to operating no more than 4,380 hr/yr per Condition 4 of Permit No. AQ0316MSS03.

2.0 Methodology: The Top-Down Approach

The methodology used to identify BACT for the proposed emission units is the five step "top-down" methodology set forth in EPA New Source Review Rule Revisions (proposed) (Federal Register Vol. 61, No. 142, July 23, 1996). The emission units and pollutants subject to a BACT review are identified in Table 1-2.

The first step of the BACT analysis is to survey alternative control techniques and identify all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions units and pollutants under evaluation. The following guidelines are used to identify available control options:

> The technology should be "demonstrated in practice". The control technology should have been installed and operating at a minimum of 50 percent of capacity for six months, and the performance should have been verified with a test or operational data at 90 percent of operational capacity.
>
> Controls applied to similar source categories, gas streams, and innovative control technologies should be examined. Process controls, such as combustion modifications, that are currently available from a supplier should be reviewed.

In step two, the technical feasibility of each available control option is evaluated based on source-specific factors. The use of control options, which would clearly result in technical difficulties precluding their successful use, is deemed technically infeasible.

In step three, the effectiveness of control alternatives is determined for all options not eliminated in step two. Control options are then ranked "top-down" in order of overall control effectiveness for the pollutant under review.

In step four, the energy, environmental, and economic impacts of control options are considered, beginning with the top-ranked control alternative. If the most effective control option is shown to be inappropriate due to adverse impacts, that option is eliminated and the next most stringent alternative is evaluated. If the most stringent technology is selected as BACT, continuing the analysis is not necessary.

Finally, in step five, the most effective control option not eliminated in step four is proposed as BACT for the pollutant and emission unit under review.

The basis for comparing the economic impacts of control scenarios is cost effectiveness. This value is defined as the total net annualized cost of control, divided by the tons of pollutant removed per year, for each control technique. Annualized costs include the annualized capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, replacement parts, overhead, raw materials, and utilities.

Capital costs include both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, startup costs and contingencies.

In this analysis, all costs are expressed as an annualized cost, and cost-effectiveness values are then calculated. This approach of amortizing the investment into equal end-of-year annual costs is termed the Equivalent Uniform Annual Cost (EUAC). This approach is the EPA recommended method for estimating control costs.

3.0 NO_X BACT Analysis

NO_X is formed as a by-product of combustion. NO_X contributes indirectly to the formation of $PM_{2.5}$ through atmospheric chemical reactions that produce nitrates, a form of particulate matter. This BACT analysis includes a review of control technologies that could reduce NO_X emissions either by reducing the formation of NO_X during combustion or post-combustion controls that eliminate NO_X in the flue gas. As shown in Table 1-2, the emission units for which a NO_X BACT analysis is required are:

- EU ID 113, a large circulating fluidized bed (CFB) coal and biomass-fired boiler;
- EU IDs 3 and 4, mid-sized diesel-fired and dual fuel-fired (diesel and natural gas-fired) boilers, respectively;
- EU IDs 19, 20, and 21, small diesel-fired boilers;
- EU ID 8, a large diesel-fired engine;
- EU ID 27, a small diesel-fired engine; and
- EU ID 9A, a pathological waste incinerator.

EU IDs 103 through 105, 107, 109 through 111, 114, and 128 through 130 are all material handling equipment which do not have any combustion emissions. As a result, a NO_X BACT analysis is not needed for those emission units.

The tables supporting the NO_X BACT analysis which identify the available control options, technically feasible options, ranking of technically feasible control options, cost of technologies and summaries of the proposed BACT can be found at the end of Section 3.

3.1 Available NO_X Control Options

The EPA RACT/BACT/LAER Clearinghouse (RBLC) has been reviewed to identify available control technology for emission units similar to the emission units at UAF. This clearinghouse of information was reviewed for emission units permitted during the past ten years, from January 1, 2005 through August 24, 2015. All applicable control options from the RBLC are considered in this BACT analysis. In addition, control technologies from equipment vendors and other known possible control technologies have been included in this analysis. The NO_X emission information found in the RBLC for each type of emission unit is included in Appendix A for reference. Supporting vendor and contractor information for the NO_X BACT analysis can be found in Appendix B.

3.1.1 Large CFB Coal and Biomass-fired Boiler (EU ID 113) – NO_X Control Options

The large CFB coal and biomass-fired boiler (EU ID 113) is rated 295.6 million British thermal units per hour (MMBtu/hr) heat input and has a CFB combustor design. Coal is expected to be the primary fuel for this boiler, but woody biomass could also be combusted. The RBLC was reviewed for NO_X BACT control technology applications on large boilers rated at 250 MMBtu/hr or greater. Entries for both large coal-fired boilers (RBLC Process ID 11.110) and large biomass-fired boilers (RBLC Process ID 11.120) were reviewed. Summaries of the results can be found in Table A-1 of Appendix A. Many of the control technology entries for coal and biomass-fired boilers were the same. A number of the boilers were identified as CFB boilers, but many boilers were identified as the traditional pulverized coal (PC) design or the combustor design was not identified.

Some RBLC boiler entries identified multiple BACT controls on individual boilers if the units were equipped with both combustion burner emission reduction designs and post-combustion add-on control technologies. Although not found in the RBLC review, non-selective catalytic reduction (NSCR) is included in this review.

Identified NO_X control technologies for large coal-fired and biomass-fired boilers include:

- Selective Catalytic Reduction (SCR);
- Selective Non-catalytic Reduction (SNCR);
- NSCR;
- Low NO_X Burners (LNB)/Overfired Air(OFA)/Flue Gas Recirculation (FGR)/ Staged Combustion;
- CFB;
- Low Excess Air; and
- Good Combustion Practices.

SCR – Large CFB Boiler NO_X Control Option

SCR is a post-combustion gas treatment technique for reduction of nitric oxide (NO) and nitrogen dioxide (NO_2) in the exhaust stream to molecular nitrogen, water, and oxygen. In the SCR process, aqueous or anhydrous NH_3 is used as the reducing agent, and is injected into the flue gas upstream of a catalyst bed. The function of the catalyst is to lower the activation energy of the NO_X decomposition reaction. NO_X and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. Depending on the overall ammonia-to-NO_X ratio, removal efficiencies are generally between 70 and 90 percent (EPA-452/F-03-032).

According to the RBLC, of the NO_X control technologies that were permitted for similar boilers, more than one in three entries identified SCR as BACT. Although SCR systems were commonly identified as BACT, a list of the recognized disadvantages of using SCR is provide below.

- A common characteristic of all SCR catalyst types is the narrow window of acceptable system inlet temperatures, typically 500 degrees Fahrenheit (F) to 800 degrees F. The reaction will not proceed below the minimum acceptable temperature. Operation above the maximum acceptable temperature results in poor NO_X reduction performance, causing oxidation of NH_3 to NO_X, and potentially generating explosive levels of ammonium salts in the exhaust gas. The EU ID 113 normal exhaust temperature is expected to range from approximately 1,550 degrees F to 1,650 degrees F. Applying SCR to the boiler would require installing a system to cool the exhaust gas.

- Some vendors advertise ceramic catalysts which can operate at temperatures higher than conventional catalysts. Little demonstrated operating experience exists for these catalysts. The RBLC search discovered only one CFB boiler with SCR. That case makes no mention of using a high temperature catalyst.
- A number of environmental hazards are associated with SCR. These systems generally operate with a molar NH_3/NO_X ratio greater than the ratio required by the stoichiometry of the reduction reaction to achieve optimal conversion efficiencies. This operation results in the passage of toxic and odorous NH_3 to the atmosphere, called NH_3 slip. Ammonia is more toxic than NO_X and is classified as a hazardous material by EPA.
- If the depleted catalysts cannot be reclaimed, then disposal as hazardous waste may be required.

Even though significant disadvantages are noted for the use of SCR, the technology is an available control technology for large boilers and will be reviewed in this analysis.

SNCR – Large CFB Boiler NO_X Control Option

SNCR is a post-combustion control technology that involves the non-catalytic decomposition of NO_X in the flue gas to nitrogen and water using reducing agents, such as urea or ammonia. The process utilizes a gas phase homogeneous reaction between NO_X 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 ammonia process (trade name - Thermal DeNO_X) requires a reaction temperature window between 1,600 degrees F and 2,200 degrees F. In the urea process (trade name - NO_XOUT), the optimum temperature ranges between 1,600 degrees F and 2,100 degrees F. With combustion temperatures between 1,550 and 1,650 degrees F, this technology may require adding minor amounts of heat to the flue gas for successful operation.

An RBLC search identified multiple applications of SNCR for large boilers rated at 250 MMBtu/hr or more. SNCR is expected to achieve 40 to 62 percent NO_X control, based on the reported control effectiveness in the RBLC and 30 to 50 percent NO_X control based on the EPA fact sheet (EPA-452/F-03-031). The vendor, Babcock & Wilcox, estimated that SNCR on this boiler would have a NO_X control efficiency between 10 and 20 percent and that ammonia slip would be less than 20 parts per million (ppm). SNCR is an available control technology for the large CFB boiler.

NSCR – Large CFB Boiler NO_X Control Option

NSCR is a post-combustion control technology that is designed to simultaneously reduce NO_X and oxidize carbon monoxide (CO) and hydrocarbons (HC) in the combustion gas to nitrogen, carbon dioxide (CO_2), and water. The catalyst, usually a noble metal, causes the reducing gases in the exhaust stream (hydrogen [H_2], methane [CH_4], and CO) to reduce both NO and

NO_2 to nitrogen at temperatures between 800 degrees F and 1,200 degrees F. NSCR requires a low excess oxygen concentration in the exhaust gas stream to be effective because the oxygen 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 to fuel (A/F) ratio controller at or close to stoichiometric conditions.

The RBLC search discovered no applications of NSCR for large boilers since 2005. This result occurred because boilers operate under conditions far more fuel-lean (with excess oxygen) than required to support feasible application of this technology. The boiler is anticipated to have exhaust gas between 1,550 degrees F and 1,650 degrees F, which is well above the recommended exhaust temperature range. Flue gas cooling would be required. The RBLC did not identify NSCR as a technology available to boilers of this size and design. NSCR is not an available control technology because the proposed large boiler is not of a rich-burn design.

LNB/OFA/FGR/Staged Combustion – Large CFB Boiler NO_X Control Option

LNB restrict the formation of NO_X by lowering the thermal NO_X formation created by high flame temperature in the presence of oxygen. The key to limiting thermal NO_X formation is to reduce peak flame temperature and restrict oxygen availability and exposure at peak flame temperature. This goal can be achieved through several combustion chamber designs which include OFA, FGR, and staged combustion.

OFA systems are often a part of an overall NO_X reduction strategy in boilers referred to as LNB. Applying OFA, a portion of air from the burners is removed to reduce oxygen availability early in the combustion process and is reintroduced later in the combustion process. This action reduces the availability of oxygen to form NO_X in the combustion zone which reduces the peak temperature in the combustion zone, ultimately lowering NO_X formation. Regardless of whether the air is reintroduced through ports located above the combustion zone or elsewhere, this process is described as OFA.

Staged combustion is the same principle as OFA. Staged combustion burners are the most common type of LNB. Staged combustion can be achieved by staging the injection of either air or fuel in the near burner region. Staged air combustion reduces NO_X formation using the reduced air strategy described for OFA, by reducing the amount of available air to form NO_X in the combustion chamber. With less air to combust, the combustion temperature is reduced so less thermal NO_X is formed. Staged fuel combustion burners inject the fuel in multiple combustion zones, which reduces the formation of NO_X by keeping the peak combustion temperature lower and lowering the quantity thermal NO_X formation.

Upon closer review of the RBLC data, staged combustion technology is the only LNB technology that has been identified as NO_X BACT for large CFB boilers. Only pulverized coal boilers have used OFA and FGR for NO_X emission control. The proposed CFB boiler design includes staged combustion with the primary air jets raising the coal and limestone to be above the boiler feed bed and with secondary air being injected above the fed bed through the walls of the boiler. As a result, staged combustion is available for the CFB boiler and will be the only version of LNB technology considered in this BACT analysis.

CFB – Large CFB Boiler NO_X Control Option

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 NO_X.

Fluidized bed technology is an available combustion design technology for lowering NO_X formation with the additional bonus of controlling sulfur emissions when limestone is introduced. Because the proposed large boiler will have CFB and staged combustion, these two technologies will be reviewed together through the remainder of this BACT analysis.

Low Excess Air – Large CFB Boiler NO_X Control Option

Boiler operation with low excess air is considered an integral part of good combustion air management practices because this process can maximize the boiler efficiency while controlling the formation of NO_X. Boilers operated with five to seven percent excess air typically have the peak NO_X formation from both peak combustion temperatures and chemical reactions. At both lower and higher excess air concentrations the formation of NO_X 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 NO_X and CO generation is minimized and the boiler efficiency is optimized. Only one RBLC entry identified low excess air technology as a NO_X control alternative for a mass-feed stoker designed boiler. Boilers are regularly designed to operate with low excess air as described in the various LNB combustion designs described above. Low excess air control technology will not be carried forward as an available control technology in this NO_X BACT analysis for large boilers because the air flow to the boiler is already reduced through the boilers proposed staged combustion design.

Good Combustion Practices – Large CFB Boiler NO_X Control Option

Large boilers that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining a boiler in peak operating condition is in the interest of every owner because the boiler lifespan will be optimized. Operating a boiler according to manufacturer recommendation will keep the boiler at the highest level of efficiency, reduce strain on the boiler, and optimize operating costs.

Good combustion practices are an available control technology for large CFB coal and biomass-fired boilers.

3.1.2 MID-SIZED DIESEL-FIRED BOILERS (EU IDs 3 AND 4) – NO_X CONTROL OPTIONS

The mid-sized diesel-fired boilers (EU IDs 3 and 4) are rated at 180.9 MMBtu/hr maximum heat input, each. These units are operated to provide supplemental heat and as backup boilers should the main boilers fail. EU ID 3 is permitted as a dual fuel-fired boiler for both diesel and natural gas, but the boiler is only configured to fire diesel fuel. As a result, this BACT analysis will only focus on diesel firing for EU ID 3. EU ID 4 is also permitted as a dual fuel-fired boiler for both diesel and natural gas fuels. EU ID 4 is capable of firing both fuels, so this BACT analysis will consider that ability for that boiler. EU ID 4 has a permitted annual capacity factor of 10 percent, so although these two similar package boilers have the same rated capacity, EU ID 4 is significantly restricted operationally.

A review of the RBLC for diesel-fired boilers with a heat input rating between 100 and 250 MMBtu/hr (process code 12.220) identified one boiler that was subject to a BACT analysis in the past 10 years. That analysis showed a “no controls” determination. Table A-6 in Appendix A provides this RBLC summary. A review of the RBLC for natural gas-fired boilers with a heat input rating between 100 and 250 MMBtu/hr (process code 12.310) identified multiple control options.

Both the diesel-fired and natural gas-fired boiler control technologies will be considered for these mid-sized boilers. SNCR will also be considered as a known NO_X control technology even though SNCR did not appear in either RBLC inventories for mid-sized boilers. Identified NO_X control technologies for mid-sized diesel and natural gas-fired boilers include:

- SCR;
- SNCR;
- LNB/FGR;
- Natural Gas;
- Limited Operation; and
- Good Combustion Practices.

SCR – Mid-sized Boilers NO_X Control Option

SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in the exhaust stream to molecular nitrogen, water, and oxygen. In the SCR process, aqueous or anhydrous NH_3 is used as the reducing agent, and is injected into the flue gas upstream of a catalyst bed. The function of the catalyst is to lower the activation energy of the NO_X decomposition reaction. NO_X and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. Depending on the overall ammonia-to-NO_X ratio, removal efficiencies are generally between 70 and 90 percent.

For a number of reasons, SCR may not be an ideal NO_X control technology for these mid-sized boilers. Some recognized disadvantages of using SCR are discussed below.

- A common characteristic of all SCR catalyst types is the narrow window of acceptable system inlet temperatures, typically 500 degrees F to 800 degrees F. The reaction will not proceed below the minimum acceptable temperature. Operation above the maximum acceptable temperature results in poor NO_X reduction performance, causing oxidation of NH_3 to NO_X, and potentially generating explosive levels of ammonium salts in the exhaust gas. The normal exhaust temperature for EU IDs 3 and 4 ranges between approximately 340 degrees F and 400 degrees F, according to heat exchanger data available to Stanley Consultants, Inc. (SCI). Applying SCR to the boilers would require installing a system to heat the exhaust gas.
- Backpressure in the boiler due to the catalyst system can be a problem that may require re-sizing the fan.
- A number of environmental hazards are associated with SCR. These systems generally operate with a molar NH_3/NO_X ratio greater than the ratio required by the stoichiometry of the reduction reaction to achieve optimal conversion efficiencies. This operation results in the passage of toxic and odorous NH_3 to the atmosphere, called NH_3 slip. Ammonia is more toxic than NO_X and is classified as a hazardous material by EPA.
- If the depleted catalysts cannot be reclaimed, then disposal as hazardous waste may be required.

Even though significant disadvantages to using SCR exist, the technology is an available control technology for these mid-sized boilers and will be reviewed in this NO_X BACT analysis.

SNCR – Mid-sized Boilers NO_X Control Option

SNCR is a post-combustion control technology that involves the non-catalytic decomposition of NO_X in the flue gas to nitrogen and water using reducing agents, such as urea or ammonia. The process utilizes a gas phase homogeneous reaction between NO_X 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 ammonia process (trade name - Thermal $DeNO_X$) requires a reaction temperature window between 1,600 degrees F and 2,200 degrees F. In the urea process (trade name - NO_XOUT), the optimum temperature ranges between 1,600 degrees F and 2,100 degrees F. With combustion temperatures between 340 and 400 degrees F, this technology would require that heat be added to the flue gas for successful operation.

An RBLC search discovered no applications of SNCR for mid-sized diesel or natural gas-fired boilers since 2005. SNCR is expected to achieve 30 to 50 percent NO_X control without LNB and 65 to 75 percent when operated with LNB according to the EPA fact sheet (EPA-452/F-03-031). Although no applications of SNCR for mid-sized boilers could be identified, SNCR is an available control technology for the mid-sized boilers.

LNB/FGR – Mid-sized Boilers NO_X Control Option

LNB restricts the formation of NO_X by lowering the thermal NO_X formation created by high flame temperature in the presence of oxygen. The key to limiting the thermal NO_X is to reduce peak flame temperature and restrict oxygen availability and exposure at the peak flame temperature. LNB can use a staged combustion design to minimize NOx formation and FGR to further reduce NOx formation as identified in the RBLC.

Staged combustion is described above for the large CFB boiler NO_X control. Staged combustion burners are the most common type of LNB. Staged combustion can be achieved by staging the injection of either air or fuel in the near burner region. Staged air combustion reduces NO_X formation using a reduced air strategy, by reducing the amount of available air to form NO_X in the combustion chamber. With less air to combust, the combustion temperature is reduced so less thermal NO_X is formed. Staged fuel combustion burners inject the fuel in multiple combustion zones which reduced the formation of NO_X by keeping the peak combustion temperature lower, and so lowering the quantity of thermal NO_X created.

The addition of FGR to a LNB allows flue gas to be recirculated back into the combustion chamber. This recirculated flue gas acts as a heat sink by absorbing heat from the flame and lowering peak flame temperatures. The recirculated flue gas also dilutes the combustion air lowering the oxygen content of the air, starving the NO_X forming reaction of one of the necessary reaction chemicals.

These various techniques all achieve the reduction of NO_X by reducing the potential thermal NO_X formation. These technologies will be referred to as LNB technologies in this BACT analysis.

EU IDs 3 and 4 are described as having a LNB design, but the LNB design is only applicable to these boilers while firing natural gas. Because EU ID 3 is not able to fire natural gas, the unit does not include a LNB design for the current operation. EU ID 4, which is the dual fuel-fired boiler and is restricted by a 10 percent annual capacity factor, only uses LNB while firing natural gas. While firing on diesel, the boilers use standard combustion. No staged combustion, OFA or FGR exists in the burner design for diesel firing that would qualify these boilers as LNB units.

LNB/FGR designs have been used as a retrofit NO_x control for existing boilers and can achieve approximately 35 to 55 percent reduction from uncontrolled levels (1995, EPA). LNB/FGR is an available NO_X control technology for these mid-sized boilers while firing diesel. Indeck, the vendor currently supporting these Zurn boilers, has supplied information about emission reductions for these boilers if new LNB/FGR boilers were to be installed. Indeck estimates the NO_X emission reduction to be 66.7 to 68.6 percent for these boilers if a new LNB/FGR system were to be installed.

Natural Gas – Mid-sized Boilers NO_X Control Option
Only EU ID 4 has the ability to burn natural gas. Natural gas combustion has a lower NO_X emission rate than diesel combustion, so natural gas can be a preferred fuel for this reason. The availability of natural gas in Fairbanks is limited. Natural gas must be trucked to Fairbanks because no pipeline system currently exists to deliver natural gas to Fairbanks. UAF must retain the ability to burn diesel in EU ID 4 during the times natural gas is not available. EU ID 4 is permitted to emit no more than 40 tons per year (tpy) of NO_X whether the unit burns diesel or natural gas. As a result, a switch to only natural gas-firing will not reduce the NO_X emission potential from EU ID 4.

EU ID 3 is not configured to burn natural gas. Because Fairbanks does not have a pipeline source, natural gas is not an available fuel for consideration for this boiler. During the times that EU ID 4 is firing natural gas, operators have noticed a pressure loss in the natural gas supply. Operating both boilers on natural gas at the same time would only exacerbate this pressure loss unless the natural gas delivery system was to be changed.

For the above reasons, switching to only fire natural gas as a control technology is not an available option for either EU ID 3 or 4.

Limited Operation – Mid-sized Boilers NO_X Control Option
Because EU ID 4 has limited operation due to permit restrictions, this limit is an available NO_X emission control. With fewer available hours of operation, the annual potential NO_X emissions are reduced. This approach is not always practical to control NO_X emissions because not all emission units can be operated in a limited manner while sustaining electrical and steam output commitments. Regardless of this constraint, limited operation is an available BACT control technology for NO_X emissions from the boilers.

Good Combustion Practices – Mid-sized Boilers NO_X Control Option
Mid-size boilers that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining a boiler in peak operating condition is in the interest of every owner because the boiler lifespan will be optimized. Operating a boiler according to the manufacturer recommendation will keep the boiler at the highest level of efficiency, lower fuel costs, reduce strain on the boiler, and optimize operating costs.

Good combustion practices are an available control technology and are standard practice for UAF.

3.1.3 SMALL DIESEL-FIRED BOILERS (EU IDs 19 THROUGH 21) – NO_X CONTROL OPTIONS

The small diesel-fired boilers (EU IDs 19 through 21) are rated at 6.13 MMBtu/hr, each. These three boilers are identical in make, model, and use. These small boilers are permitted to operate combusting ultra-low sulfur diesel (ULSD) and share an allowable annual hourly operating limit.

The review of the RBLC for small diesel-fired boilers rated at less than 100 MMBtu/hr (process code 13.220) found several entries for small boilers with burner designs to control NO_X emissions. Table A-11 lists the RBLC control options found for these boilers. No add-on NO_X control options were identified for these small boilers. Identified NO_X control technologies for small diesel-fired boilers include:

- LNB/FGR;
- Limited Operation; and
- Good Combustion Practices.

LNB/FGR – Small Diesel-fired Boilers NO_X Control Option

LNB restrict the formation of NO_X by lowering the thermal NO_X formation created by high flame temperature in the presence of oxygen. The key to limiting the thermal NO_X is to reduce peak flame temperature and restrict oxygen availability and exposure at peak flame temperature. This goal can be achieved through FGR boiler designs. Several RBLC entries identified both LNB and FGR together as the NOx control option for small boilers.

FGR involves recycling a portion of the combustion gases from the stack to the boiler combustion air intake. The low oxygen combustion products, once mixed with the combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature and the residence time at peak flame temperature. These effects work together to limit thermal NO_X formation.

These various techniques all achieve the reduction on NO_X by reducing the potential thermal NO_X formation. These technologies will be referred to as LNB technologies in this BACT analysis. LNB designs have been used as a retrofit NO_X control for existing boilers and can achieve approximately 35 to 55 percent reduction from uncontrolled levels (1995, EPA). LNB is an available NO_X control technology for these small boilers firing diesel.

Limited Operation – Small Diesel-fired Boilers NO_X Control Option

The three small boilers share an operating limit of 19,650 hours per year. With fewer available hours of operation, the annual potential NO_X emissions are reduced. Limited operation is an available NO_X control technology for these small boilers.

Good Combustion Practices – Small Diesel-fired Boilers NO_X Control Option
Small boilers that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining a boiler in peak operating condition is in the interest of every owner because the boiler lifespan will be optimized. Operating a boiler according to the manufacturer recommendation will keep the boiler at the highest level of efficiency, which lowers fuel costs, reduces strain on the boiler, and optimizes operating costs. Good combustion practices are an available control technology.

3.1.4 LARGE DIESEL-FIRED ENGINE (EU ID 8) – NO_X CONTROL OPTIONS

UAF has one large diesel-fired engine (EU ID 8) rated at 13,266 horsepower (hp). This engine has a turbocharger, an intercooler, and a SCR system, which controls NOx formation and emissions. The engine shares a 40 tpy NO_X emission limit with EU ID 4.

The RBLC was reviewed for NO_X control options on similar engines (RBLC Process ID 17.110) from the past ten years. A summary of the findings are provided in Table A-15 of Appendix A. Many emission control options were identified for large diesel-fired engines, including:

- SCR;
- Reduce NO_X 90 Percent (methodology not specified);
- Turbocharger and Aftercooler;
- Fuel Injection Timing Retard (FITR);
- Ignition Timing Retard (ITR);
- Federal Standard;
- Limited Operation; and
- Good Combustion Practices.

SCR – Large Diesel-fired Engine NO_X Control Option
SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in the exhaust stream to molecular nitrogen, water, and oxygen. In the SCR process, aqueous or anhydrous NH_3 is used as the reducing agent, and is injected into the flue gas upstream of a catalyst bed. The function of the catalyst is to lower the activation energy of the NO_X decomposition reaction. NO_X and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. Depending on the overall ammonia-to-NO_X ratio, removal efficiencies are generally 70 to 90 percent.

One RBLC NO_X determination was identified for SCR for large engines. EU ID 8 has an SCR system at this time which cannot be operated as currently installed due to excess visible emissions that result from the design of the exhaust gas ducting and stack on the downstream side of the SCR system. Operating the SCR system is not required to comply with the 40 tpy NO_X emission limit in Condition 16 of Permit No. AQ0316TVP02, but operating the system would enable increased actual operating hours for EU ID 8. The SCR system has a 90 percent

NO_X control efficiency and is permitted for a 5 ppm ammonia slip. As a result, SCR is an available control technology.

Reduce NO_X 90 Percent – Large Diesel-fired Engine NO_X Control Option
Reducing NO_X by 90 percent is a very general control option determination in the RBLC for one engine. This determination does not specific a control strategy for reaching 90 percent NO_X control. The determination implies the use of an add-on control device to achieve this level of NO_X control. This control option is not an available NO_X control option because the determination fails to identify the method to achieve this level of control. Because SCR is an available NO_X control option for large engines and SCR can control 90 percent of NO_X emissions, the Reduce NO_X 90 Percent control option is available for further review.

Turbocharger and Aftercooler – Large Diesel-fired Engine NO_X Control Option
Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature which reduces NO_X formation in the combustion chamber.

EU ID 8 is operating with a turbocharger and aftercooler. As a result, turbocharger and aftercooler design is an available control option for this engine.

FITR – Large Diesel-fired Engine NO_X Control Option
The RBLC identified three entries from 2007 at the same facility for FITR for NO_X emission control from large diesel engines. The three large engines are either firewater pump engines or emergency engines.

With FITR, NO_X emissions are reduced by delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. Retrofitting the engine with a FITR would require changing the cam.

The downsides to FITR is that the engine becomes less fuel efficient, an increase in particulate matter emissions results, and a limit exists with respect to the degree the timing may be retarded because excessive timing delay can cause the engine to misfire. For these reasons, timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR was a popular NO_X control technology through the 1990s. Because of a limited ability to reduce NO_X emissions to no less than 4 grams per kilowatt-hour (g/kWh), FITR has been replaced by new and more effective NO_X control technologies (2015, Jaaskelainen). FITR can achieve up to 50 percent NO_X control efficiency (1999, EPA). Because FITR can increase particulate matter emissions while reducing NO_X emissions, this control technology is not appropriate for use in a serious $PM_{2.5}$ nonattainment area. Other control technologies are available to achieve much better NO_X reductions, such as the SCR system that is already installed on this engine. For these reasons, FITR is not an available control technology for this analysis.

ITR – Large Diesel-fired Engine NO_X Control Option

The RBLC identified multiple entries of ITR for NO_X control of large engines. ITR lowers NO_X emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not at as high, which lowers combustion temperature and produces less thermally formed NO_X. Tradeoffs exist with the use of ITR, including a possible increase in fuel usage, increase in particulate matter emissions, and the risk of misfire. The typical NO_X emission reduction with ITR from compression ignition engines is 20 to 30 percent (2007, IL EPA). Because ITR can increase particulate matter emissions while reducing NO_X emissions, this control technology is not appropriate for use in a serious $PM_{2.5}$ nonattainment area. Other control technologies are available that achieve much better NO_X reductions, such as the SCR system that is already installed on this engine. For these reasons, ITR is not an available control technology for this analysis.

Federal Standard – Large Diesel-fired Engine NO_X Control Option

Multiple RBLC NO_X determinations identified that large engines are required to meet federal emission standards. The RBLC determinations indicated the listed engines were to meet New Source Performance Standards (NSPS) requirements of 40 Code of Federal Regulations (CFR) 60 Subpart IIII, non-road engine (NRE) standards, or EPA certification. Subpart IIII has performance standards for stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The age, rating, and size of the compression cylinder will determine whether an applicable federal emission standard is included in Subpart IIII, is referenced to the NRE standards, or the engine comes with a manufacturer's certification of meeting the required federal standards. All stationary engines must meet the required applicable federal emission limit.

EU ID 8 was installed in 1999 and has not been reconstructed since that time. The Subpart IIII emission standards are not applicable to EU ID 8 because Subpart IIII has no emission standards for engines installed in 1999. As a result, the use of complying with the federal emission standards is not an appropriate control option for EU ID 8 and will not be considered any further in this analysis.

Limited Operation – Large Diesel-fired Engine NO_X Control Option

Several RBLC determinations identified limiting the engine operation as the NO_X emission control option. Fewer hours of operation reduces the potential annual NO_X emissions. This approach is not always practical for controlling NO_X emissions because not all emission units can be operated in a limited manner while sustaining electrical commitments. EU ID 8 has existing limits on NO_X and SO_2 emissions which limit operations. As a result, limited operation is an available BACT control for NO_X emissions from the large engine.

Good Combustion Practices – Large Diesel-fired Engine NO_X Control Option
Engines that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining an engine in peak operating condition is in the interest of every owner because the engine lifespan will be optimized. Operating an engine according to the manufacturer's recommendation will keep the engine at the highest level of efficiency, lower fuel costs, reduce strain on the engine, and optimize operating costs. Good combustion practice is an available control option.

3.1.5 SMALL DIESEL-FIRED ENGINE (EU ID 27) – NO_X CONTROL OPTIONS

UAF has one small diesel-fired engine (EU ID 27) rated at 500 hp. This Tier 3 engine incorporates LNB through the use of a turbocharger and aftercooler. The engine also has a 4,380 hour per year operating limit. The RBLC was reviewed for NO_X emission control options on similar engines (RBLC Process ID 17.210) from the past ten years. A summary of the findings are provided in Appendix A. Although SCR was not identified in the RBLC, this technology has been included because of a broad effectiveness at controlling NO_X emissions. The following control options were identified for the small diesel-fired engine:

- SCR;
- Turbocharger and Aftercooler;
- ITR;
- Federal Standard;
- Limited Operation; and
- Good Combustion Practices.

SCR – Small Diesel-fired Engine NO_X Control Option
SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in the exhaust stream to molecular nitrogen, water, and oxygen. In the SCR process, aqueous or anhydrous ammonia is used as the reducing agent, and is injected into the flue gas upstream of a catalyst bed. The function of the catalyst is to lower the activation energy of the NO_X decomposition reaction. NO_X and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. Depending on the overall ammonia-to-NO_X ratio, removal efficiencies are generally 70 to 90 percent.

SCR is an available control technology for this small engine.

Turbocharger and Aftercooler – Small Diesel-fired Engine NO_X Control Option
Common combustion technology includes the use of a turbocharger and aftercooler in the engine design. Turbocharger technology involves the process of compressing intake air in a

turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature, which reduces NO_X formation in the combustion chamber.

EU ID 27 has a turbocharger and aftercooler as part of the engine design. As a result, turbocharge and aftercooler is an available control technology for this small engine.

ITR – Small Diesel-fired Engine NO_X Control Option

The RBLC identified one entry of ITR for NO_X control from small engines. ITR lowers NO_X emissions by moving the ignition event to later in the power stroke, once the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high. With this lower temperature, less thermally formed NO_X is created during the combustion products. Tradeoffs exist with the use of ITR, including a possible increase in fuel usage, a possible increase in particulate matter emissions, and the risk of misfire. The typical NO_X emission reduction with ITR from compression ignition engines is 20 to 30 percent (2007, IL EPA). Because ITR can increase particulate matter emissions while reducing NO_X emissions, use of this control technology is not appropriate in a serious $PM_{2.5}$ nonattainment area. For this reason, ITR is not an available control technology for this analysis.

Federal Standard – Small Diesel-fired Engine NO_X Control Option

Multiple RBLC NO_X determinations identified the determination that small engines are required to meet federal emission standards. The RBLC determinations indicate the engines were to meet 40 CFR 60 Subpart IIII limits, nonroad engine (NRE) standards, or EPA certification limits. Subpart IIII has performance standards for stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The age, rating, and size of the compression cylinder determine whether an applicable federal emission standard is included in Subpart IIII, referenced to the NRE standards, if the engine must be provided with a manufacturer's certification of meeting the required federal standards, or if no applicable federal standard exists. All stationary engines subject to an applicable federal emission limit must comply with the limits.

EU ID 27 was recently manufactured and installed. The unit is a certified Tier 3 engine and is in compliance with the applicable federal standard. As a result, meeting a federal standard is an available control option for this engine.

Limited Operation – Small Diesel-fired Engine NO_X Control Option

Only a few RBLC determinations identified limiting the engine operation as the NO_X control option. With fewer available hours of operation, the annual potential NO_X emissions are reduced. This approach is not always practical to control NO_X because not all emission units can be operated in a limited manner while sustaining the needed electrical commitments. EU ID

27 is limited to 4,380 hours of operation per year. As a result, limited operation is an available control option.

Good Combustion Practices – Small Diesel-fired Engine NO_X Control Option
Small engines that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining an engine in peak operating condition is in the interest of every owner because the engine lifespan will be optimized. Operating an engine according to the manufacturer's recommendation will keep the engine at the highest level of efficiency, lower fuel costs, reduce strain on the engine, and optimize operating costs. Good combustion practice is an available control technology and is standard practice for UAF.

3.1.6 MEDICAL/PATHOLOGICAL WASTE INCINERATOR (EU ID 9A) – NO_X CONTROL OPTIONS

The medical/pathological waste incinerator, EU ID 9A, is designed to properly dispose of animals remains in a safe and efficient manner. The pathological waste incinerator is equipped with an afterburner that has a multiple chamber design. The afterburner fires supplemental diesel fuel to augment the destruction of pathological wastes. EU ID 9A is rated to process one ton of waste per day. An owner requested limit of 109 tpy total of waste restricts the incinerator's operation, per Condition 8 of the Operating Permit.

A review of the RBLC for hospital, medical and infectious waste incinerators (RBLC Process ID 21.300) for the past ten years produced only one entry. This entry identified multiple chambers as the control option for the incinerator, as seen in Table A-23 of Appendix A. Additional add-on control technologies will be reviewed to be certain a broad review of NO_X control technology is conducted. Although not found in the RBLC review, limited operation is included in the analysis because EU ID 9A has an existing operating limit. NO_X control options identified for consideration for the medical/pathological waste incinerator include:

- SCR;
- SNCR;
- LNB;
- Multiple Chambers;
- Limited Operation; and
- Good Combustion Practices.

SCR – Medical/Pathological Waste Incinerator NO_X Control Option
As described above for many types of emission units, SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in the exhaust stream to molecular nitrogen, water, and oxygen. In the SCR process, aqueous or anhydrous ammonia is used as the reducing agent, and is injected into the flue gas upstream of a catalyst bed. The function of the catalyst is to lower the activation energy of the NO_X decomposition reaction. NO_X and NH_3 combine at the

catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. Depending on the overall ammonia-to-NO_X ratio, removal efficiencies are generally 70 to 90 percent.

Although no RBLC NO_X BACT determinations were identified for pathological waste incinerators, an RBLC review of the municipal waste incinerator category (RBLC Process ID 21.400) did identify two SCR systems on those units. Municipal waste incinerators are much larger units with a waste handling capacity of 1,000 tons per day to over 2,000 tons per day. These municipal waste incinerators are 1,000 to over 2,000 times larger in rated capacity than the UAF medical/pathological waste incinerator. Similar to the concerns described above for SCR on other emission units, SCR may not be an ideal NO_X control technology for pathological waste incinerators. The incinerator exhaust may not fall within the narrow window of acceptable temperatures. NH_3 slipped into the atmosphere is more toxic than NO_X and is classified as a hazardous material by EPA. The disposal of the spent catalyst may require treatment as a hazardous waste. Even though significant disadvantages exist to using SCR for post-combustion incinerator emission control, the technology is an available control technology for the incinerator and will be reviewed in this analysis.

SNCR – Medical/Pathological Waste Incinerator NO_X Control Option

SNCR, as described above in the review for other emission units, is a post-combustion control technology that involves the non-catalytic decomposition of NO_X in the flue gas to nitrogen and water using reducing agents, such as urea or ammonia. The process utilizes a gas phase homogeneous reaction between NO_X and the reducing agent within a specific temperature window.

An RBLC search discovered no applications of SNCR for hospital, medical or infectious waste incinerators since 2005. An RBLC review of the municipal waste incinerator category identified SNCR on two incinerators rated at 200 and 600 tons per day of waste throughput. These municipal waste incinerators are 200 to 600 times larger in rated capacity than the UAF medical waste incinerator. Although no applications of SNCR to pathological waste incinerators were identified, SNCR is an available control technology.

LNB – Medical/Pathological Waste Incinerator NO_X Control Option

LNB restrict the formation of NO_X by lowering the thermal NO_X formation created by high flame temperature in the presence of oxygen. The key to limiting the thermal NO_X is to reduce peak flame temperature and restrict oxygen availability and exposure at peak flame temperature. Use of LNB is an available control for the incinerator.

Multiple Chambers – Medical/Pathological Waste Incinerator NO_X Control Option

Only one RBLC entry for hospital, medical and infectious waste incinerators was found from a review of the last ten years. The identified NO_X control technology for this incinerator was listed as the same technology as for particulate matter (PM) emission control technology. The listed control technology was multiple chambers and temperature control. Multiple chambers introduce the waste material and a portion of the combustion air in the primary chamber. The secondary chamber introduces the remaining air to complete the combustion of all incomplete combustion products which mainly reduces the production of PM. The secondary chamber allows for a longer residence time at a reduced temperature which will render pathological waste to be innocuous and produce less PM emissions through the destruction of organic PM in the secondary chamber during the long residence time. The overall mass of NO_X emissions increases in a multi-chambered incinerator with these long combustion residence times while the PM emissions decrease. The RBLC listing as a NO_X control is incorrect.

EU ID 9A is designed with an afterburner that is a secondary combustion chamber or multiple chamber incinerator. This afterburner is a very effective method for destroying pathogens which can produce organic particulate matter. This control technology will be reviewed in the PM section of the BACT. Multiple chambers are not an available incinerator NO_X control technology because this technology does not reduce NO_X emissions.

Good Combustion Practices – Medical/Pathological Incinerator NO_X Control Option
Incinerators that follow good combustion practices are maintained and operated according to manufacturer instructions and conventional industry practices. Maintaining an incinerator in good operating conditions is in the interest of every owner because the incinerator lifespan will be optimized and the highest level of destruction of pathological material is enabled. Good combustion practices are an available control technology.

Limited Operation – Medical/Pathological Incinerator NO_X Control Option
While the RBLC did not identify limited operation as a NO_X control option, fewer available hours of operation does reduce the annual potential NO_X emissions. EU ID 9A is limited to 109 tpy of waste combustion. As a result, limited operation is an available control option.

3.1.7 SUMMARY OF AVAILABLE NO_X CONTROL OPTIONS

Table 3-1 summarizes the available NO_X control options that are subject to this BACT analysis. The large coal and biomass-fired boiler (EU ID 113) has four available NO_X emission control options. Staged combustion and CFB are part of the proposed burner design and will be considered together in the remainder of this analysis. Two of the control options, SCR and SNCR, are competing post-combustion control technologies. The final available control technology is good combustion practices.

The mid-sized diesel-fired boilers (EU IDs 3 and 4) have SCR, SNCR, LNB/FGR, limited operation, and good combustion practices as available NO_X emission control options. The use of natural gas fuel was eliminated as an available control option because Fairbanks does not receive pipeline natural gas services to fully support natural gas availability.

Small boilers have the retrofit control option of LNB along with limited operation and good combustion practices as available NO_X emission control options.

For EU ID 8, the large diesel-fired engine, eight NO_X emission control options were identified. Four of these options are available. Table 3-1 lists each of these control options. Of these available control technologies, EU ID 8 is already designed to operate with a turbocharger and aftercooler. EU ID 8 has an installed SCR system which cannot be used as installed. EU ID 8 also has limited operation based on the NO_X emission limit that is shared with EU ID 4. SCR and good combustion practices are the additional control options under consideration for BACT.

The small diesel-fired engine, EU ID 27, is a Tier 3 engine that uses turbocharger and aftercooler control technology to meet the federal emission limit. This engine also has an hourly operating restriction. Table 3-1 identifies SCR and good combustion practices as other available emission control options.

SCR and SNCR add-on control options are considered available for the medical/pathological waste incinerator, EU ID 9A, along with LNB, limited operation, and good combustion practices.

3.2 Technical Feasibility of Available NO_X Control Options

The following subsections provide the technical feasibility analyses for the available NO_X emission control alternatives for each emission unit. The technically feasible NO_X control options are shown in Table 3-2.

3.2.1 LARGE COAL AND BIOMASS-FIRED BOILER (EU ID 113) – NO_X TECHNICAL FEASIBILITY

SCR and SNCR are considered available and feasible technologies by vendors for the large coal and biomass-fired boiler. Because this large boiler is still in the planning stages at this time, either one of these post-combustion controls could be considered in the project design.

CFB and staged combustion are proposed to be incorporated into the burner design of the large boiler. As a result, these two technologies will jointly be carried forward as a technically feasible NO_X control option. Good combustion practices are always a feasible control technology for large boilers and are technically feasible for the boiler.

3.2.2 MID-SIZED DIESEL-FIRED BOILERS (EU IDs 3 AND 4) – NO_X TECHNICAL FEASIBILITY

SCR is a technically feasible control option for EU ID 3. SCR is not a technically feasible control option for EU ID 4 due to space constraints around this boiler.

As seen in Figure 3-1, EU ID 4 is located on the east side of the existing Atkinson Combined Heat and Power Plant at UAF. The building is surrounded by the ash loading facility and truck access to the south, a close property line and existing roadway immediately to the north, facility parking and a building egress stair to the east, and the remainder of the Atkinson facility to the west. Within the existing plant building, horizontal space is occupied by fuel, water and steam lines, burners, the primary combustion chamber, and combustion air and flue gas ductwork. Vertical space is occupied by a tubular air heater located immediately above the boiler exhaust breech. The presence of the administrative spaces directly above the boiler room eliminates the potential for growth in the vertical direction.

The addition of an SCR system to EU ID 4 would add the following equipment to an already crowded footprint: the SCR reactor, structural steel to support the reactor, incoming and outgoing ductwork from the reactor, urea/ammonia storage and mixing, feed lines into the reactor and access for maintenance and repair activities.

Based on a review of the available space in this portion of the power plant, severe limitations exist on available space for add-on control equipment between the boiler and the exhaust stack. As previously stated, the limitations are both in the horizontal and vertical directions. In addition, the building does not have sufficient space to be expanded in any direction due to the existing equipment described above, the administrative spaces, and the available property around the facility. For these reasons, a SCR control system is not viable from a technical perspective for EU ID 4.

SNCR is not a technically feasible control option for mid-sized diesel-fired boilers or mid-sized natural gas-fired boilers. The RBLC inventories did not identify any SNCR systems in operation as BACT, Lowest Achievable Emission Rate (LAER), Maximum Achievable Control Technology (MACT) or other determination. New source review requires that a control technology be demonstrated through at least six months of operation with operations of at least 50 percent of capacity and the performance is to be verified with a test or operational data at 90 percent of operational capacity to be considered a demonstrated control option. SNCR is not a demonstrated NO_X control option for diesel-fired boilers rated between 100 and 250 MMBtu/hr, because no RBLC entries in the past ten years identified this control option as being applied to this category of emission unit.

LNB is commonly identified as a mid-sized boiler NO_X emission control technology. LNB is used while firing natural gas on EU ID 4, but is not used while EU IDs 3 and 4 are firing diesel. Replacing the current standard fuel oil burners with LNB/FGR burners is a technically feasible control option for these boilers.

Limited operation is technically feasible for EU ID 4 because the unit currently operates with an annual heat input restriction which limits NO_X emissions. EU ID 3 does not currently have any operating limits. EU ID 3 is needed as a backup to the existing large boilers and the proposed new CFB boiler, should those boilers fail. As a result, limited operation is technically feasible only for EU ID 4. Limited operation is not technically feasible for EU ID 3.

Good combustion practices are a feasible control technology for both boilers.

3.2.3 SMALL DIESEL-FIRED BOILERS (EU IDs 19 THROUGH 21) – NO_X TECHNICAL FEASIBILITY

This subsection describes the technical feasibility analyses for the available NO_X control alternatives for the small diesel-fired boilers. LNB combustor designs are commonly identified as a small boiler NO_X emission control technology. LNB combustor designs are a technically feasible control option for these boilers.

These boilers have limited hourly operations under Condition 10 of Air Quality Permit No. AQ0316MSS03. UAF cannot reduce the operations of these boilers to levels below this restriction without adversely affecting facility needs. The use of limited operations controls emissions from these boilers more than good combustion practices. As a result, good combustion practices will not be carried forward since limited operations are required by the permit and are a better NO_X control option. Although eliminated from BACT consideration, good combustion practices will be implemented for other reasons.

3.2.4 LARGE DIESEL-FIRED ENGINE (EU ID 8) – NO_X TECHNICAL FEASIBILITY

EU ID 8 is currently operating under a shared 40 tpy NO_X limitation. UAF cannot further restrict the operation of EU ID 8 because the engine is needed to maintain the operation and integrity of the power generation facility. Limited operation of EU ID 8 is technically feasible and already in place.

EU ID 8 currently operates with a turbocharger and aftercooler. Although the SCR system cannot be used as installed, the system can be modified. SCR is a technically feasible control technology. Because EU ID 8 is equipped with a turbocharger, aftercooler and limited operation, these controls are technically feasible.

Because the turbocharger aftercooler control options offer more NO_X emission control than good combustion practices, no need exists to carry good combustion practices forward in this analysis. Although eliminated from BACT consideration, good combustion practices will be implemented for other reasons.

3.2.5 SMALL DIESEL-FIRED ENGINE (EU ID 27) – NO_X TECHNICAL FEASIBILITY

SCR is a technically feasible add-on NO_X control technology for EU ID 27. Because federal standards and limited operations are already a part of the engine design and operation, these technically feasible control options will be considered together as a control option. Because these control options offer more NO_X emission control than good combustion practices, no need exists to carry good combustion practices forward in this analysis. Although eliminated from BACT consideration, good combustion practices will be implemented for other reasons.

3.2.6 MEDICAL/PATHOLOGICAL WASTE INCINERATOR (EU ID 9A) – NO_X TECHNICAL FEASIBILITY

SCR and SNCR are both add-on NO_X control technologies. Based on the EU ID 9A permitted limit to combust no more than 109 tpy of waste, the potential NO_X emissions from EU ID 9A is 0.2 tpy. The amount of NO_X controlled using an SCR or SNCR with 90 percent control would be 0.18 tpy of NO_X. Given the low concentration and mass amount of NO_X in the exhaust stream, the reasonable expectation is that neither SCR nor SNCR would be effective at removing large quantities of NO_X from the exhaust steam. As shown by the RLBC search results, no hospital, medical or infectious waste incinerators have installed SCR or SNCR systems. Expanding the RBLC search to municipal waste incinerators identified two incinerators with SCR systems and two incinerators with SNCR systems. These municipal waste incinerators were 200 to 2,000 times larger in rated capacity than EU ID 9A. Given that EU ID 9A processes no more than one ton of waste per day and has an operating limit, installing an SCR or SNCR system on EU ID 9A is not technically feasible based on the lack of demonstrated use and low NO_X concentrations in the exhaust.

Discussions with Therm-Tech, the pathological waste incinerator vendor, indicated that LNB is only an available control technology for natural gas-fired pathological waste incinerators. The UAF incinerator is diesel-fired. Natural gas at UAF is only available at the power plant, not near the incinerator. Natural gas is only available in limited quantities because no natural gas pipeline to Fairbanks exists. As a result, switching the incinerator to natural gas-firing and the use of a LNB is not possible. On this basis, LNB is not a technically feasible control technology for the incinerator.

The use of good combustion practices is technically feasible for EU ID 9A. Limited operation is technically feasible for EU ID 9A because the unit currently operates with an annual waste combustion limit which limits NO_X emissions. Because good combustion practices and limited operation are the only technically feasible control technologies for EU ID 9A, these options will be proposed as BACT. No further NO_X BACT review will be conducted for the incinerator.

3.2.7 SUMMARY OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS

Table 3-2 shows the technically feasible NO_X technologies for the emission units. This table presents two add-on control technologies for the large coal-fired boiler along with one boiler design control option and good combustion practices. The technically feasible NO_X control option for mid-sized boilers has been divided into two analyses because SCR is technically feasible only for EU ID 3. Upgrading the burners to LNB/FGR for diesel-firing and good combustion practices are technically feasible options for both of these mid-sized boilers. Table 3-2 shows LNB as the only technically feasible add-on retrofit for small diesel-fired boilers along with limited operation.

Also shown in Table 3-2, the large diesel-fired engine has two technically feasible NO_X emission control option entries. One option is to modify the existing SCR system to enable operation. The other option is a combination of the existing NO_X emission controls on this engine. These controls include a turbocharger and aftercooler and limited operation.

Table 3-2 shows two technically feasible NO_X control options for the small diesel-fired engine, EU ID 27. These options are SCR and the joint emission control options systems currently being practiced. Those joint emission control options are turbocharger and aftercooler, federal emission standards, and limited operation.

Good combustion practices and limited operation are the only technically feasible options for the medical/pathological waste incinerator, EU ID 9A. Good combustion practices and limited operation will be proposed as BACT for the incinerator and no further BACT review will be conducted for EU ID 9A.

3.3 Summary of Ranking of Technically Feasibility NO_X Control Options

Each technically feasible control technology is ranked in order of overall NO_X control effectiveness. Each subsection describes the ranking of the feasible control technologies.

3.3.1 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – NO_X RANKING OF TECHNICAL FEASIBILITY

The large boiler is proposed to include CFB and staged combustion into the boiler design. The use of CFB and staged combustion is the base case for the boiler ranking. The post-combustion control technologies will be ranked by controlling the emissions from this base case. Replacing the proposed CFB and staged combustion with a boiler simply operating using good combustion practices does not offer as much NO_X control as the proposed CFB and staged combustion. For this reason, good combustion practices have not been included in the ranking of technically feasible control technologies in Table 3-3.

Full operation of EU ID 113 with CFB and staged combustion is expected to produce a maximum of 259 tpy of NO_X emissions. SCR post-combustion control technology generally is expected to control 80 percent of NO_X emissions per manufacturer information. SNCR post-combustion control technology is estimated to control 10 to 20 percent of the NO_X emissions according to the boiler vendor. This analysis will conservatively assume SNCR can control 20 percent of the NO_X emissions. Table 3-3 shows the potential NO_X emissions and the amount of NO_X emission reduction for each control option.

3.3.2 MID-SIZED DIESEL-FIRED BOILERS (EU IDs 3 AND 4) – NO_X RANKING OF TECHNICAL FEASIBILITY

The mid-sized diesel-fired boilers have no currently installed NO_X emission control technology. Because EU ID 4 has a permitted NO_X emission limit and a capacity factor limit, EU ID 4 will be analyzed separately from EU 3.

As shown in Table 3-3, for EU ID 3, SCR has the largest NO_X control efficiency, followed by LNB/FGR control technology. Good combustion practices do not change the potential NO_X emissions for boiler EU ID 3. Good combustion practices are the base case for emissions.

EU ID 4 shares a NO_X emission limit of 40 tpy with EU ID 8. EU ID 4 also has a 10 percent annual capacity factor limit, which is more restrictive than the shared NO_X limit. As shown in Table 3-3, LNB/FGR has an estimated NO_X control of less than 9 percent. Good combustion practices are the base case for emissions.

3.3.3 SMALL DIESEL-FIRED BOILERS (EU IDs 19 THROUGH 21) – NO_X RANKING OF TECHNICAL FEASIBILITY

Retrofitting these small boilers with a LNB would be expected to reduce NO_X emissions from each boiler by 35 to 55 percent according to AP-42. Discussions of emissions using a LNB were discussed with Proctor Sales Inc. The vendor indicated that the lowest emission achievable by a LNB retrofit would be 100 ppm of NO_X, plus or minus 10 ppm. (See Appendix B for a copy of the Proctor Sales Inc. information.) Based on this emission rate, SCI has estimated that emissions from a LNB would be 1.41 pounds per hour, each, for a combined total of 13.87 tpy with the 19,650 hours per year operating restriction. The LNB emission estimate is larger than the current boiler emission estimate which is based on AP-42 emission factors. The current boiler design has lower NO_X emissions than if the boilers were retrofitted with LNB. As a result, the current limited operation of these boilers ranks higher than retrofitting the boiler with a LNB with limited operation.

Based on this information, the use of limited operation will be proposed as BACT for these three small diesel-fired boilers. No further NO_X BACT review will be conducted for EUs 19 through 21.

3.3.4 LARGE DIESEL-FIRED ENGINE (EU ID 8) – NO_X RANKING OF TECHNICAL FEASIBILITY

EU ID 8 is a large diesel-fired engine equipped with a turbocharger and aftercooler. This engine also has NO_X and SO_2 emission limits which restrict operations. These control options are the base case for determining emissions.

The addition of SCR to the base case for EU ID 8 results in a higher level of NO_X emission control. As shown in Table 3-3, the SCR system can be 90 percent effective and reduce NO_X emissions from 40 tpy to 4 tpy.

3.3.5 SMALL DIESEL-FIRED ENGINE (EU ID 27) – NO_X RANKING OF TECHNICAL FEASIBILITY

EU ID 27 is an engine that incorporates a turbocharger and aftercooler to achieve the federal Tier 3 emission limits. This engine also has an annual operating limit. Because EU ID 27 already is operating under the federal Tier 3 limits and has limited operation, these control options are the base case for determining emissions.

The addition of SCR to the base case emissions for EU ID 27 results in a higher level of NO_X emission control. As shown in Table 3-3, the SCR can remove 90 percent of the remaining emissions and reduces NO_X emissions to less than 1 tpy.

3.3.6 SUMMARY OF NO_X RANKING OF TECHNICAL FEASIBILITY

The ranking of each control option for the various emission units is summarized in Table 3-3. Each of these control options will be reviewed for additional impacts in the following sub-section with the exception of the control technologies for EU IDs 19 through 21. The traditional base case emissions for EU IDs 19 through 21 are limited operation, which shows lower emissions than retrofitting these boilers with LNB and maintaining the limited operation. Because only one control option remains under review for EU IDs 19 through 21 and this option was found to cause higher emissions than the base case, UAF will propose that the base case of limited operation be NO_X BACT.

3.4 Additional Impacts of Technically Feasible NO_X Control Options

The following subsections describe the energy, environmental, and economic impacts associated with the alternative control options for the various equipment. The control technology offering the greatest level of NO_X removal is reviewed for impact. If the control technology offering the greatest level of NO_X control is not appropriate for BACT, then the next control technology offering the second greatest level of NO_X removal is reviewed. If the second greatest level of NO_X control is not BACT, then the review continues until a technically feasible emission control technology is identified.

Cost estimates were prepared for the various control technologies by SCI with input from control technology vendors. The supporting cost estimates from SCI can be found in Tables 3-5 through 3-17.

3.4.1 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – SCR + (CFB WITH STAGED COMBUSTION)

The SCR system for the CFB boiler has been roughly designed by the boiler vendor Babcock & Wilcox. The SCR system is estimated to control 80 percent of the NO_X emissions using a catalyst and aqueous ammonia. The vendor information can be found in Appendix B.

Energy Impacts

The application of SCR technology to the boiler would result in the need for power to operate the aqueous ammonia system and the ammonia injection grid to allow the catalyst to work. As a result, energy consumption at UAF would increase if SCR equipment is to be installed.

Environmental Impacts

Multiple environmental impacts occur from the use of SCR technology. Potential hazards exist from the regular transport of ammonia or aqueous ammonia to Fairbanks. This boiler is located on a college campus and very near two high schools, so UAF is especially concerned about risks to these student populations. Use of aqueous ammonia is proposed. Excess ammonia that is consumed in the SCR system will be released to the atmosphere through ammonia slip. Additional products of combustion are generated due to the increased fuel combustion needed to generate power to pump and heat the aqueous ammonia solution and to make up the power lost due to the catalyst system backpressure. The catalyst is estimated by the vendor to have a two year life span and must then be trucked off-site for disposal or reclamation.

Babcock & Wilcox proposed the use of 29 percent aqueous ammonia to facilitate the catalytic reaction instead of anhydrous ammonia. Both aqueous and anhydrous ammonia are more toxic than NO_X.

A SCR system would require continuous adjustments of the ammonia injection rate to match the NO_X formation. An ammonia deficiency causes NO to react with O_2 causing more NO_X to be generated and excess ammonia leads to an increase of slip released to the atmosphere. Operating below the optimal range will reduce the catalytic activity thus allowing excess ammonia to 'slip' through the system. A properly designed SCR system can provide control efficiencies of 80 to 90 percent and commonly has an ammonia slip rate of 10 ppm. Babcock & Wilcox estimated the ammonia consumption rate for an SCR system with 80 percent control efficiency.

Economic Impacts

Only a few of the capital and annualized cost estimates for providing SCR system for the large CFB boiler were provided by Babcock & Wilcox in the document provided in Appendix B. SCI provided additional SCR system costs estimates.

The estimated cost of basic equipment shown in Table 3-4 is expected to include the SCR equipment, catalyst, ammonia injection grid, aqueous ammonia storage tank and accoutrements, but not the additional necessary instrumentation, freight, labor or direct installation costs. SCI has estimated the costs of startup spares and vendor representative fees based on past project experience. SCI assumes the cost of direct installation costs are twice the basic equipment costs based on information supplied by Fuel Tech in Appendix B regarding SCR equipment costs for other emission units at UAF. The indirect costs for engineering, procurement and construction support services are based on SCI past project experience and the management and contingency costs are based on information supplied by Fuel Tech.

As shown in Table 3-4 the estimated total capital investment cost is $26,740,640 for an SCR NO_X control system. Table 3-5 shows the estimated annual cost to operate an SCR system and the associated equipment. No labor costs have been estimated at this time. No estimated cost is included for the cost for maintenance materials or to operate the support equipment for the SCR. SCI has estimated the ammonia costs, energy costs, and catalyst replacement costs, but has not included the cost of transporting aqueous ammonia to Fairbanks. The catalyst is estimated by the vendor to operate at an 80 percent NO_X reduction rate and is assumed the catalyst will require replacement on a two year cycle. SCI has estimated administrative charges and insurance at three percent of the total capital investment based on the *OAQPS Control Cost Manual* recommended factors. Since UAF is a public institution it does not pay property tax which often would be included in this entry at an extra one percent.

A standardized ten year return on investment at seven percent interest rate is assumed for the capital recovery estimate. Because of the harsh climate, equipment in Interior Alaska is subject to more wear and tear than equipment located in moderate climates. On this basis, a ten year return on the SCR system investment is reasonable. A seven percent interest rate is used to account for the time value of money.

The annualized cost effectiveness is based on the total annualized costs and the amount of NO_X removed by the SCR system. The annualized cost effectiveness is estimated at $28,425 per ton of NO_X removed. This cost effectiveness rate is extremely high, and would be higher if the estimate were to include the capital and annual costs not otherwise included in the estimate. Based on this cost effectiveness estimate, SCR is not economically feasible and will not be determined to be BACT.

3.4.2 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – SNCR + (CFB WITH STAGED COMBUSTION)

Energy Impacts

Babcock & Wilcox is designing the large coal and biomass-fired boiler with a CFB and staged combustion. Babcock & Wilcox supplied information addressing the use SNCR equipment on this boiler. Babcock & Wilcox estimated that SNCR would require minimal additional operating, maintenance, and power costs. The reagent used to operate the SNCR system would require heating to prevent freezing, but these costs have not been estimated at this time. No additional energy impacts are associated with SNCR control technology.

Environmental Impacts

Babcock & Wilcox estimated the use of 29 percent aqueous ammonia at 20 pounds per hour, which presents safety concerns around transport, storing, handling, and disposal. Both aqueous and anhydrous ammonia are more toxic than NO_X. This boiler is located on a college campus and very near two high schools, so UAF is especially concerned about risks to these student populations. An environmental impact will result from the ammonia slip, which is expected to be less than 20 ppm.

Economic Impacts

An economic analysis has been conducted for the installation of SNCR. The vendor of the new boiler was contacted for costs to install an SNCR system on the boiler. The vendor estimated that an SNCR system would cost approximately $1,000,000 in equipment costs to install and operate the control device. Appendix B contains this cost estimate from Babcock & Wilcox. This cost estimate is shown in the total capital investment calculation in Table 3-6. The cost estimate includes the basic equipment cost and is assumed to include all instrumentation, freight, labor and vendor representative fees. Direct installation costs are estimated to be equivalent to the basic equipment costs based on comments from Fuel Tech that an SCR system on EU ID 113 would cost twice the basic equipment costs. Because an SNCR system is less complicated than an SCR system, SCI estimated by that the direct installation costs would be equivalent to the equipment costs.

SCI has estimated that engineering, procurement and construction support services of the indirect costs are 18 percent of the total direct costs based on past project experience. The contingency costs are assumed to be 30 percent of the total direct costs based on SCR equipment information available from Fuel Tech.

The cost effectiveness estimate for SNCR is found in Table 3-7. Very few annual costs are provided. Babcock & Wilcox estimated the reagent usage, which is the only direct annual cost estimated in the table. The indirect annual cost estimate includes administrative charges, property taxes, insurance and the capital recovery. SCI estimated the administrative charges and insurance as three percent of the total capital investment based on their past project experience.

A standardized ten year return on investment at seven percent interest rate is assumed for the capital recovery estimate based on the *OAQPS Control Cost Manual* recommendations. Because of the harsh climate, equipment in Interior Alaska is subject to more wear and tear than equipment in moderate climates. On this basis, a ten year return on the SNCR system is reasonable. A seven percent interest rate is used to account for the time value of money.

The annualized cost effectiveness is based on the total annualized costs and the amount of NO_X removed by the SNCR system. The annualized cost effectiveness is estimated at $10,192 per ton of NO_X removed without including most annual operating costs. This cost effectiveness rate is very high, making SNCR cost prohibitive. Based on this cost effectiveness estimate, SNCR is not economically feasible and will not be determined to be BACT.

3.4.3 MID-SIZED DIESEL-FIRED BOILER (EU ID 3) – SCR

An SCR system for this BACT analysis is based on information from Fuel Tech for a system that would control 85 percent of the NO_X emissions. The SCR system requires the use of a catalyst and aqueous urea to form ammonia. Direct and indirect expenses for installation of an SCR system on the boiler and annual costs for maintaining the system has been estimated. These costs are shown in the Fuel Tech documents found in Appendix B along with additional SCR project costs estimated by SCI.

Energy Impacts

The application of SCR technology to the boiler will result in the need for power to operate the urea feed system and the ammonia injection grid to allow the catalyst to work. As a result, energy consumption at UAF will increase if SCR equipment is installed on this boiler.

Environmental Impacts

Multiple environmental impacts occur from the use of SCR technology. Because potential hazards exist with the regular transport of ammonia or aqueous ammonia to Fairbanks, the use of aqueous urea is proposed to reduce the transportation hazards of ammonia. This boiler is located on a college campus and very near two high schools, so UAF is especially concerned about risks to these student populations. Once the urea is converted to ammonia and used in the SCR system, ammonia slip will be released to the atmosphere. Additional products of combustion are generated due to the increased fuel combustion needed to generate power to pump and heat the aqueous urea solution and to make up for the lost power caused by the catalyst backpressure. The catalyst is guaranteed to have a two year life span and then must be either hauled off-site for disposal or reclamation.

UAF is proposing the use of 50 percent aqueous urea to facilitate the catalytic reaction, instead of aqueous or anhydrous ammonia, to minimize the safety concerns around transport, storing, handling, and disposal. Both aqueous and anhydrous ammonia are more toxic than NO_X. A 50 percent aqueous urea solution has a freezing point of 60 degrees F, which will require heating the delivery solution, storage tanks and piping to allow year-round operation of the SCR system. The freezing point of aqueous urea drops to the lowest temperature of 11 degrees F when the solution is 32.5 percent aqueous urea. This solution is also known as Diesel Exhaust Fluid (DEF) and is used for on-highway vehicles. The use of DEF would require UAF to install larger storage tanks or have more frequent deliveries.

An SCR system would require continuous adjustments of the ammonia injection rate to match the NO_X formation. An ammonia deficiency causes NO to react with O_2 causing more NO_X to be generated and excess ammonia leads to an increase of slip released to the atmosphere. Operating below the optimal range will reduce the catalytic activity thus allowing excess ammonia to ‘slip’ through the system. A properly designed SCR system can provide control efficiencies of 70 to 90 percent or better with ammonia slip of less than 10 ppm. Fuel Tech has designed a system for these boilers with an 85 percent efficiency and an ammonia slip of 5 ppm.

Economic Impacts

Many of the capital costs and annualized costs for an SCR system on the mid-sized boiler have been estimated by Fuel Tech in a document provided in Appendix B. Additional SCR system project costs are estimated by SCI.

The estimated cost of basic equipment shown in Table 3-8 includes the SCR system with catalyst, an ammonia injection grid, aqueous urea storage tank, urea forwarding pump module, a metering and distribution module, a decomposition chamber with injection, two site trips totaling 20 field man days and all equipment and system engineering with drawings, operations and maintenance manuals, and training manuals.

SCI has estimated the cost of a NO_X analyzer and the associated initial performance testing. SCI has also estimated freight costs for the SCR equipment and materials as well as the cost of startup spare parts for the system.

Fuel Tech has estimated the cost of installation along with a typical scope of supply by others as twice the equipment and services costs. The installation costs account for the cost of installation labor and materials, structural steel and foundations, insulation, heating the aqueous ammonia and the ammonia injection grid, soot blowers for catalysts as needed, demineralized water for intermittent flushing, air compressors, supporting structures, piping, wiring, installation engineering, BOP engineering, and installation project management, and more. These installation costs and additional scope of supply by others costs do not include a NO_X analyzer.

As shown in Table 3-8, the estimated total capital investment cost is $3,434,525 for an SCR NO_X control systems. Table 3-9 shows the estimated annual cost to operate an SCR system and the associated equipment. SCI has estimated the annual labor costs, urea costs, energy costs, and catalyst replacement costs. The estimate does not include the cost for maintenance materials or to operate the support equipment for the SCR system. The catalyst is guaranteed by the vendor to operate at an 85 percent NO_X reduction rate for 16,000 hours. SCI has estimated administrative charges and insurance at three percent of the total capital investment.

Similar to the economic analyses above, the standardized ten year return on investment at seven percent interest rate is assumed for the capital recovery estimate. Because of the harsh climate, equipment in Interior Alaska is subject to more wear and tear than equipment in moderate climates. On this basis, a ten year return on the SCR system investment is assumed to be reasonable. A seven percent interest rate is used to account for the time value of money.

The annualized cost effectiveness is based on the total annualized costs and the amount of NO_X removed by the SCR system. The annualized cost effectiveness is estimated at $8,416 per ton of NO_X removed. This cost effectiveness rate is high given that several capital and annual costs are not included in the estimate and because this boiler does not generally operate annually at more than five percent of the potential heat input. Because the SCR cost-effectiveness value is expected to be higher than $8,416 per ton of NO_X removed and because the boiler is operated infrequently, SCR is not economically feasible and will not be determined to be BACT.

3.4.4 MID-SIZED DIESEL-FIRED BOILER (EU ID 3 AND 4) – LNB/FGR

Information about the installation of a new burner on the boiler that is already equipped with a LNB and FGR is based on vendor information from Indeck, the current manufacturer representing Zurn boilers. Indeck estimates that a new LNB/FGR system will reduce NOx emissions from these boilers by less than 43 percent. These costs are shown in the Indeck documents found in Appendix B along with additional LNB/FGR project costs estimated by SCI.

Energy Impacts

The application of LNB/FGR technology to the boiler will result in the need for power to operate the forced draft fan. As a result, energy consumption at UAF will increase if a LNB/FGR system is installed.

Environmental Impacts

In addition to the NOx reduction, the vendor has identified that CO emissions will be reduced by about 37 percent. No additional reagents are necessary to operate the LNB/FGR system. The additional energy necessary to operate the forced draft fan will require an increase in power production, but will have a marginal impact on the emissions.

Economic Impacts

Two economic analyses are presented to represent each boiler specifically. Indeck estimated equipment costs individually for each boiler. The potential NO_X emissions for each boiler are significantly different.

The basic equipment costs for LNB/FGR systems for EU IDs 3 and 4 are provided on Tables 3-10 and 3-12. These tables show the costs to install LNB and FGR systems on each boiler. SCI has estimated the freight costs and the direct installation costs for EU ID 4 based on project experience and Haskell has estimated the direct installation costs for EU ID 3 in the April 5, 2016 email in Appendix B. The Indeck proposed costs do not include receipt, unloading and installation of the burner and all auxiliary equipment. These costs have not been estimated at this time. Additional costs not included in the capital cost tables are for foundation work, combustion air ducting, combustion control devices, and many FGR system components as described by Indeck in the February 5, 2016 letter.

Indeck believes these two boilers are not identical in size based on the available original purchasing information. For this reason, the total capital investment costs are not identical for these two boilers.

The annualized cost only includes an estimated administrative charge, insurance and the capital recovery factor. No additional operating costs have been estimated at this time. These boilers have significantly different potential NO_X emissions, so the cost effectiveness values are different for these two boilers. The cost effectiveness for LNB/FGR for EU ID 3 is $3,634 per ton of NO_X removed, while the cost effectiveness for EU ID 4 is $189,312 per ton of NO_X removed. Because the 10 percent capacity factor limits potential NO_X emissions from EU ID 4, the cost effectiveness is extremely large and unreasonable. A LNB/FGR system is not economically feasible for EU ID 4 and will not be determined to be BACT.

EU ID 3 does not have any potential emission restrictions and has a lower cost effectiveness than EU ID 4. Historically, EU ID 3 is often operated less frequently than EU ID 4 because EU ID 4 is a newer, more efficient boiler. UAF maintains the full potential operating capability of EU ID 3 so that the boiler can be operated if the main coal-fired boilers are not operational. UAF must maintain the full potential operational ability of EU ID 3 to provide heat and electricity should the main boilers becoming unavailable for any reason. Without having EU ID 3 available, the loss of the coal-fired boilers during the winter months would be catastrophic for the university because of losing heat and power to the campus. Available assessable emission data for EU ID 3 indicates NO_X emissions from 2011 through 2014 have been 6.1 tpy or less, which is less than five percent of the PTE. If the cost effectiveness of a LNB/FGR system were to be based on the actual operation during these five years, the cost effectiveness of LNB/FGR would be approximately $35,500 per ton of NO_X removed. Based on this analysis, LNB/FGR is not an economically feasible technology and will not be determined to be BACT for EU ID 3.

Good combustion practices will be proposed as BACT for EU ID 3 because all other technically feasible control options are not cost effective. Limited operation and good combustion practices will be proposed as BACT for EU ID 4 because all other control options are not cost effective.

3.4.5 LARGE DIESEL-FIRED ENGINE (EU ID 8) – SCR + (TURBOCHARGER/AFTERCOOLER + LIMITED OPERATION)

The SCR system considered for this BACT analysis would control 90 percent of the NO_X emissions beyond the emission reductions already achieved by the NO_X emission limit of 40 tpy. SCR requires the use of aqueous urea to form ammonia and a catalyst to enable the NO_X reduction reaction. Because EU ID 8 has an installed SCR system which cannot currently be used and would require reactivation, the analysis uses the reactivation costs as the basis for the BACT analysis. As a result, the cost effectiveness calculation is based on total annual direct and indirect costs, but excludes capital recovery because an SCR system is already in place. Direct and indirect expenses for reactivating the SCR and annual costs for maintaining the system have been estimated. These costs are shown in the Table 3-14.

Energy Impacts

The application of SCR technology to the engine will result in an increase in backpressure on the engine due to a pressure drop across the catalyst bed. The increased backpressure will, in turn, reduce the engine power output and reduce fuel efficiency. Engines with SCR require that additional fuel be burned to achieve the same output power as engines without SCR. Additionally, power will be needed by the ammonia pumping and heating system. As a result, energy consumption for UAF will increase if SCR were to be installed.

Environmental Impacts

Multiple environmental impacts occur from the use of SCR technology. Potential hazards exist from the regular transport of ammonia or aqueous ammonia to Fairbanks. This engine is located on a college campus and very near two high schools, so UAF is especially concerned about risks to these student populations. Use of aqueous ammonia is proposed. Once the ammonia is used in the SCR system, ammonia will be released to the atmosphere due to ammonia slip. Additional products of combustion are generated to make up for the lost power caused by the catalyst backpressure. The catalyst should be replaced every two years and then must be either trucked off-site for disposal or reclamation.

UAF would use a 29 percent aqueous ammonia solution to facilitate the catalytic reaction, as this is how the SCR system is currently designed. Both aqueous and anhydrous ammonia are more toxic than NO_X.

An SCR system would require continuous adjustments of the ammonia injection rate to match the NO_X formation. An ammonia deficiency causes NO to react with O_2 causing more NO_X to be generated and excess ammonia leads to an increase of slip released to the atmosphere. Operating below the optimal range will reduce the catalytic activity thus allowing excess ammonia to 'slip' through the system. A properly designed SCR system can provide control efficiencies of 70 to 90 percent and commonly has an ammonia slip rate of 10 ppm. Babcock & Wilcox estimated the ammonia consumption rate for an SCR system on EU ID 113 with 80 percent control efficiency; scaling the reagent consumption to EU ID 8 would result in reagent consumption of 6.84 lb/hr.

Economic Impacts

Many of the capital costs and annualized costs to reactivate the existing SCR system have been estimated by SCI by scaling up from the analysis for EU ID 27. In addition to the costs shown in Table 3-14, information regarding the installation and use of SCR can be found in Appendix B. These support documents provide details about the SCR system design that affect the direct and indirect costs to install an SCR systems on the engine to achieve 90 percent NO_X control using aqueous ammonia.

The estimated capital cost of catalyst replacement is shown in Table 3-14. Direct installation costs are conservatively assumed to be double the capital cost and are consistent with other SCR installations.

As shown in Table 3-14, the estimated total capital investment cost is $8,526,324 for reactivating the SCR system.

Table 3-15 shows the estimated annual costs to operate an SCR system and the associated equipment at $940,278. SCI has estimated the ammonia costs, energy costs, and catalyst replacement costs, but has not included the cost of transporting aqueous ammonia to Fairbanks. The catalyst is estimated to operate at a 90 percent NO_X reduction rate and is assumed to require replacement on a two year cycle. SCI has estimated administrative charges and insurance at three percent of the total capital investment based on the *OAQPS Control Cost Manual* recommended factors. Because UAF is a public institution, it does not pay property tax which often would be included in this entry at one percent.

A standardized ten year return on investment at seven percent interest rate is assumed for the capital recovery estimate. Because of the harsh climate, equipment in Interior Alaska is subject to more wear and tear than equipment located in moderate climates. On this basis, a ten year return on the SCR system investment is reasonable. A seven percent interest rate is used to account for the time value of money.

The cost effectiveness calculation is based on total annual direct and indirect costs (but excludes capital recovery because an SCR system is already in place) and the amount of NO_X removed by the SCR system. The annualized cost effectiveness is estimated at $26,119 per ton of NO_X removed from the engine exhaust. This cost effectiveness rate is very high, making SCR cost prohibitive.

Based this analysis, SCR is not economically feasible and will not be determined to be BACT. UAF will propose that the use of the existing turbocharger and aftercooler and the 40 tpy NO_X limit be BACT.

3.4.6 SMALL DIESEL-FIRED ENGINE (EU ID 27) – SCR + (TURBOCHARGER/AFTERCOOLER + FEDERAL LIMIT + LIMITED OPERATION)

The SCR system considered for this BACT analysis would control 90 percent of the NO_X emissions beyond the emission reductions already achieved by Tier 3 certification and the 4,380 hour per year operating restriction. SCR requires the use of a catalyst and aqueous urea to form ammonia. Direct and indirect expenses for installation of an SCR on the engine and annual costs for maintaining the system have been estimated. These costs are shown in the Table 3-16 along with additional SCR project information and vendor information that can be found in Appendix B.

Energy Impacts

The application of SCR technology to the engine will result in an increase in backpressure on the engine due to a pressure drop across the catalyst bed. The increased backpressure will, in turn, reduce the engine power output and reduce fuel efficiency. Engines with SCR require that additional fuel be burned to achieve the same output power as engines without SCR. Additionally, power will be needed by the ammonia pumping and heating system. As a result, energy consumption for UAF will increase if SCR were to be installed.

Environmental Impacts

Multiple environmental impacts occur from the use of SCR technology. Potential hazards exist from the regular transport of ammonia or aqueous ammonia to Fairbanks. This engine is located on a college campus and very near two high schools, so UAF is especially concerned about risks to these student populations. Use of aqueous urea is proposed to reduce the transportation hazards of ammonia. Once the urea is converted to ammonia and used in the

SCR system, ammonia will be released to the atmosphere due to ammonia slip. Additional products of combustion are generated due to the increased fuel combustion needed to generate power to pump and heat the aqueous urea solution and to make up for the lost power caused by the catalyst backpressure. The catalyst should be replaced every five years and then must be either trucked off-site for disposal or reclamation.

UAF would use a 32.5 percent aqueous urea to facilitate the catalytic reaction instead of aqueous or anhydrous ammonia to minimize the safety concerns around transport, storing, handling, and disposal. Both aqueous and anhydrous ammonia are more toxic than NO_X. The benefits of 32.5 percent aqueous urea concentration is that the material has the lowest freezing temperature (12 degrees F) compared to the other common concentration of 40 percent aqueous urea (32 degrees F). The 32.5 percent aqueous urea, also known as DEF, is the material used for SCR systems on on-highway trucks and so is readily available.

An SCR system would require continuous adjustments of the ammonia injection rate to match the NO_X formation. An ammonia deficiency causes NO to react with O_2 causing more NO_X to be generated and excess ammonia leads to an increase of slip released to the atmosphere. Operating below the optimal range will reduce the catalytic activity thus allowing excess ammonia to ‘slip’ through the system. A properly designed SCR system can provide control efficiencies of 70 to 90 percent or better with ammonia slip of generally less than 10 ppm.

Economic Impacts

Many of the capital costs and annualized costs for an SCR system have been estimated by SCI based on information from NC Power Systems and Miratech Corporation. In addition to the costs shown in Table 3-16, information regarding the installation and use of SCR can be found in Appendix B. These support documents provide details about the SCR system design that affect the direct and indirect costs to install an SCR systems on the engine to achieve 90 percent NO_X control using aqueous ammonia.

The estimated cost of basic equipment shown in Table 3-16 includes the SCR system with catalyst, an ammonia injection system, a pre-evaporation skid for urea solution and aqueous urea dosing panel, an aqueous urea storage tank, and associated pumps and vessels. Additionally the other equipment and materials included in the basic equipment and auxiliary costs are instrumentation and vendor representative fees. Startup spares and freight costs have been included as individual costs. Freight costs for the equipment and materials include transport from suppliers to Fairbanks.

Direct installation costs which include the concrete, piling, structural steel, electrical, painting, insulation, above grade piping, freight, handling and erection, and functional checkouts are not estimated. The estimated indirect costs for engineering, procurement, and construction support services are based on 15 percent of the total direct costs.

As shown in Table 3-16 the estimated total capital investment cost is $151,592 for an SCR system.

Table 3-17 shows the estimated annual costs to operate an SCR system and the associated equipment at $84,554. SCI has estimated the annual operating, maintenance and supervisory labor costs.

The SCR system is designed to achieve a 90 percent NO_X reduction rate for five years before requiring catalyst replacement. The cost of replacing the catalyst is estimated and is included in the annualized cost estimate by spreading the cost of a new catalyst over five years. The catalyst costs were obtained from the Miratech Corporation. The cost to dispose of the spent catalyst which includes transporting the spent catalyst to a disposal site, has not been included in the annualized costs at this time.

Aqueous urea is to be trucked to Fairbanks and transferred to a storage tank. The aqueous urea is converted to vaporized ammonia and is then injection into the exhaust flow prior to entering the catalyst unit. Multiple truck deliveries of aqueous urea will be required to meet the annual needs of UAF to achieve a NO_X reduction of 90 percent. Although the aqueous urea costs have been determined, a cost has not been assigned to the transportation of the aqueous urea at this time.

Other costs not included in the annualized cost of operating an SCR system are the cost of lost power each year as a result of backpressure created from the catalyst and the cost of power needed to operate the SCR ammonia pumping and heating systems. These costs are not included in the annualized costs at this time and would decrease the cost effectiveness of operating an SCR system with the engine.

The indirect annual costs have been estimated. As recommended by the *EPA Air Pollution Control Cost Manual*, Section 4.2, Chapter 2, overhead has been assumed to be zero. No administrative charges or insurance costs have been estimated. Only the capital recovery cost has been estimated.

Similar to the economic analyses above, a standardized ten year return on investment at seven percent interest rate is assumed for the capital recovery estimate. Because of the harsh climate, equipment in Interior Alaska experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the SCR system is reasonable. A seven percent interest rate is used to account for the time value of money. These values are recommended in the *EPA Air Pollution Control Cost Manual*.

The annualized cost effectiveness is based on the total annualized costs and the amount of NO_X removed by the SCR system. The annualized cost effectiveness is estimated at $12,200 per ton of NO_X removed from the engine exhaust. This cost effectiveness rate is very high, making SCR cost prohibitive.

Based this analysis, SCR is not economically feasible and will not be determined to be BACT. UAF will propose that the current use of a Tier 3 certified engine and the 4,380 hours per year operating limit be BACT.

3.5 Summary of BACT Analysis for NO_X

Based on the above analyses, Table 3-18 summarizes the NO_X BACT economics for each type of equipment. Table 3-19 identifies the proposed BACT control option and the associated emission rate for each control option. Although good combustion practices are not always identified as the proposed BACT determination, UAF follows these practices for their equipment.

SCR and SNCR economic analyses for EU ID 113 both showed control options with cost effectiveness values above $10,000 per ton of NO_X removed. The proposed NO_X BACT for this large coal and biomass fired-boiler is a boiler with CFB and staged combustion with an emission rate of 0.2 lb/MMBtu. These control options are consistent with the requirements in Permit No. AQ0316MSS06 Revision 1.

The cost effectiveness of SCR for EU ID 3 is estimated to be at least $8,416 per ton of NO_X removed. This estimate is low because the economic analysis did not include many capital and annual costs nor account for the unit historically operating annually at approximately five percent of the allowed heat input. Since the actual annual boiler operation has been only five percent of the allowed operation, the cost effectiveness of SCR would actually be much larger. Similar to SCR, LNB/FGR for EU ID 3 is not cost effective because the actual annual boiler operation has not been greater than five percent of the allowed operation. As a result, the expected impact of installing a LNB/FGR system to control NO_X emissions will be marginal given the very large capital expenditure. The use of good combustion practices is proposed as NO_X BACT with an NO_X emission rate of 0.2 lb/MMBtu.

LNB/FGR for EU ID 4 was found to have a cost effectiveness value of more than $189,000 per ton of NOx removed. A LNB/FGR system is an unreasonable control option for EU ID 4. Good combustion practices and limited operation are proposed as NO_X BACT with a NO_X emission rate of 0.2 lb/MMBtu for diesel firing and 140 lb/MMscf for natural gas firing.

The currently permitted limited operation of boilers EU IDs 19 through 21 is proposed as the NO_X BACT control option with NO_X emissions of 1.24 g/MMBtu. The boilers share a 19,650 hr/yr operating limit, which is proposed as NO_X BACT.

The large diesel-fired engine, EU ID 8, has a turbocharger and aftercooler in place, and has a NO_X emission limit of 40 tpy. While EU ID 8 has an installed SCR system, the system cannot be used as installed. The cost effectiveness for reactivating the SCR system is estimated to be at least $26,000 per ton of NO_X removed, which is not appropriate as BACT. Use of the existing turbocharger, aftercooler, and operating under the existing NO_X emission limit are proposed as NO_X BACT. The associated NO_X emission rate is 0.0195 g/hp-hr.

NO_X BACT for EU ID 27 is proposed to be the use of a turbocharger and aftercooler with federal limits and limited operation. This small engine is a Tier 3 certified engine that operates with a turbocharger and aftercooler. The engine is restricted to no more than 4,380 hours of operation annually. The NOx emission rate is less than or equal to 3.2 g/hp-hr.

The control option proposed as NO_X BACT for the medical/pathological waste incinerator, EU ID 9A, is limited operation and good combustion practices with a NO_X emission rate of 3.56 lb/ton.

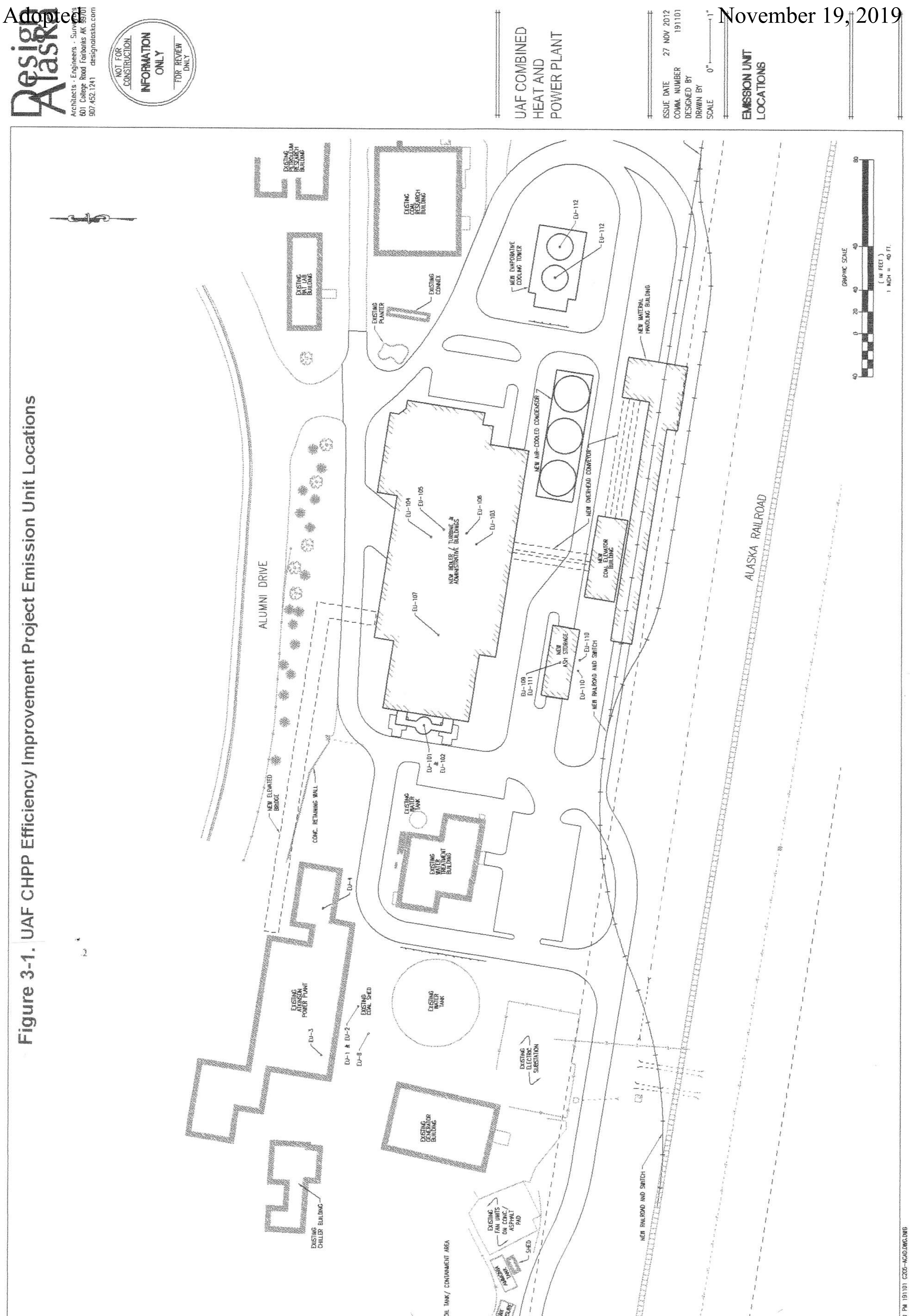

Figure 3-1. UAF CHPP Efficiency Improvement Project Emission Unit Locations

Table 3-1. UAF - Available NO_X Control Options

Emission Unit		Available Control Options
ID	**Description**	
113	Large Coal-fired Boiler	SCR
		SNCR
		CFB with Staged Combustion
		Good Combustion Practices
3 and 4	Mid-sized Diesel-fired Boilers	SCR
		SNCR
		LNB/FGR
		Limited Operation
		Good Combustion Practices
19 through 21	Small Diesel-fired Boilers	LNB
		Limited Operation
		Good Combustion Practices
8	Large Diesel-fired Engine	SCR
		Turbocharger and Aftercooler
		Limited Operation
		Good Combustion Practices
27	Small Diesel-fired Engines	SCR
		Turbocharger and Aftercooler
		Federal Standard
		Limited Operation
		Good Combustion Practices
9A	Medical/Pathological Waste Incinerator	SCR
		SNCR
		LNB
		Limited Operation
		Good Combustion Practices

Table 3-2. UAF - Technically Feasible NO_X Control Options

Emission Unit ID	Emission Unit Description	Technically Feasible Control Options
113	Large Coal-fired Boiler	SCR
		SNCR
		CFB with Staged Combustion
		Good Combustion Practices
3	Mid-sized Diesel-fired Boilers	SCR
		LNB/FGR
		Good Combustion Practices
4	Mid-sized Diesel-fired Boilers	LNB/FGR
		Limited Operation
		Good Combustion Practices
19 through 21	Small Diesel-fired Boilers	LNB
		Limited Operation
8	Large Diesel-fired Engine	SCR
		Turbocharger and Aftercooler + Limited Operation
27	Small Diesel-fired Engine	SCR
		Turbocharger and Aftercooler + Federal Standard + Limited Operation
9A	Medical/Pathological Waste Incinerator	Good Combustion Practices
		Limited Operation

Table 3-3. UAF - Ranking of Technically Feasible NO_X Control Options

Emission Unit ID	Emission Unit Description	Control Technology	Control Efficiency (pct.)	NO_X Emissions (tpy)	Emissions Reduction (tpy)
113	Large Coal and Biomass-fired Boiler	SCR + (CFB with staged combustion)	80	51.8	207.2
		SNCR + (CFB with staged combustion)	20	207.2	51.8
		CFB with staged combustion	0	259	0
3	Mid-Sized Diesel-fired Boiler	SCR	85	20.8	118.0
		LNB/FGR	42.9	79.2	59.6
		Good Combustion Practices	0	138.8	0
4	Mid-Sized Diesel and Natural Gas-fired Boiler	LNB/FGR	8.8	12.7	1.2
		Limited Operation[1]	0	13.9	0
19 through 21	Small Diesel-fired Boilers	Limited Operation[2]	N/A	8.8	NA
		LNB + Limited Operation	N/A	13.9	0
8	Large Diesel-fired Engine	SCR + (Turbocharger + Aftercooler + Limited Operation)	90	4.0	36.0
		Turbocharger + Aftercooler + Limited Operation	0	40	0
27	Small Diesel-fired Engine	SCR + (Turbocharger + Aftercooler + Federal Limit + Limited Operation)	90	0.8	6.9
		Turbocharger + Aftercooler + Federal Limit + Limited Operation	0	7.7	0

Notes:

[1]EU 4 NOx emissions are limited to 13.9 tpy by the 10 percent capacity factor in Condition 17 of Permit AQ0316TVP02 and are less than the 40 tpy shared NO_X limit with EU 8 from Condition 16 of that permit.

[2]Vendor emission estimates for retrofitting LNB on the boilers was for a higher NO_X emission rate than the AP-42 emission rate used to estimate the emissions of the boilers with limited operation.

Table 3-4. UAF - Capital Costs for SCR on the Large CFB Coal-fired Boiler (EU ID 113)

Shaded cells indicate user inputs.

Total Capital Investment Determination - SCR

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 113 - CFB Boiler)

Date: 2/2/2016
Prepared By: L. Pacini
Checked By: C. Stevenson
Rev: A

Capital Costs

DIRECT COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1)	**Purchased equipment and material costs**							
(a)	**Basic equipment**							
	Total SCR System	1	EA	6000000	$ 6,000,000			
							TOTAL = $	6,000,000
(b)	**Instrumentation**							
	Total Instrumentation		EA		$ -	Included above		
							TOTAL = $	-
(c)	**Freight**							
	SCR Freight		%	0		$ -		
							TOTAL = $	-
(d)	**Labor**							
	Labor - shop fab		MH			$ -		
	Labor - onsite		MH			$ -		
							TOTAL = $	-
(e)	**Startup Spares**							
	Startup Spare Parts for SCR	0.50%	%		$ 30,000			
							TOTAL = $	30,000
(f)	**Vendor representatives fees**							
	Fab Site Vendor Representatives fees (enter no. of days and daily rate)	10	Days	1800		$ 18,000		
	Onsite Vendor Representatives fees (enter no. of days and daily rate)	8	Days	2500		$ 20,000		
							TOTAL = $	38,000
Purchased Equipment and Material Cost (PEMC)	All above costs included in vendor scope except SCR spares and SCR vendor rep. fees						PEMC =	6,068,000
(2)	**Direct Installation Costs**							
(a)	**Concrete**		CY		$ -			$ -
(b)	**Piling**		TON		$ -			$ -
(c)	**Structural steel**		TON		$ -			$ -
(d)	**Electrical**		LOT		$ -			$ -
(e)	**Painting**		SF		$ -			$ -
(f)	**Insulation**		LOT		$ -			$ -
(g)	**Abovegrade piping**		LF		$ -			$ -
(h)	**Functional Checkouts**							
	Functional Checkout - fab site, enter %:		% offsite fab labor			$ -		$ -
	Functional Checkout - onsite, enter %		% onsite fab labor			$ -		$ -
	Contractor Commissioning, enter %:		% of equipment total cost			$ -		$ -
Direct Installation Costs (DIC) - 2 x SCR Equipment Capital							DIC =	12,000,000
Total Direct Costs (TDC)							TDC = (PEMC) + (DIC) =	18,068,000
INDIRECT COSTS								
(3)	Engineering, Procurement & Construction Support Services	18%	% TDC			$ 3,252,240		
(4)	Performance tests	0	EA			$ -		Excluded in this estimate.
Total Indirect Costs (TIC)							TIC =	3,252,240
MANAGEMENT AND CONTINGENCY COSTS								
(5)	Unit Operator Costs		% TDC					Excluded in this estimate.
(6)	Contingency	30%	% TDC			$ 5,420,400		
Total Management and Contingency Costs (TM&CC)							TM & CC =	5,420,400
TOTAL CAPITAL INVESTMENT (TCI)							TCI = (TDC)+(TIC)+(TM&CC) =	**26,740,640**

Table 3-5. UAF - Annualized Costs for SCR on the Large CFB Coal-fired Boiler (EU ID 113)

Shaded cells indicate user inputs

Cost Effectiveness Determination - SCR

Project:	UAF - $PM_{2.5}$ BACT Analysis (EU ID 113 - CFB Boiler)
Date:	2/2/2016
Prepared By:	L. Pacini
Checked By:	C. Stevenson
Rev:	A

Annualized Costs

	DIRECT ANNUAL COSTS	QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating Labor		MH		excluded in this estimate	$ -	$ -
(2)	Supervisory Labor		MH		excluded in this estimate	$ -	$ -
(3)	Maintenance Labor		MH		excluded in this estimate	$ -	$ -
(4)	Maintenance Materials		LOT		excluded in this estimate		
(5)	Utilities						
	(a) Aqueous Ammonia:	262.80	TON	200.080032	$ 52,581		$ 52,581
	(b) Energy:	613200.00	kWh	0.18	$ 110,376		$ 110,376
(6)	Catalyst Replacement Costs (every 2 years)						
	(a) Replacement of SCR Catalyst: % of total equipment cost	30%	% total equip	$ 6,068,000	$ 1,820,400.00		$ 879,420
	(b) Replacement labor for SCR Catalyst	180	MH	105		$ 18,900	$ 9,130
	(c) Transport cost direct to site (SCR catalyst)	13%	% replacement			$ 236,652	$ 114,325
	(d) Transport cost for spent SCR catalyst	13%	% replacement			$ 236,652	$ 114,325
	Sinking Fund Factor [see inputs below]:	0.4831					
	Total Direct Annual Costs (TDAC)					TDAC =	$ 1,280,157
	INDIRECT ANNUAL COSTS						
(7)	Overhead		%		excluded in this estimate	$ -	$ -
(8)	Administrative Charges and Insurance	3.00%	% total capital			$ 802,219	$ 802,219
	Capital Recovery Factor [see inputs below]	0.1424					
(9)	Capital Recovery					CRF * TCI =	$ 3,807,266
	Total Indirect Annual Costs (TIAC)					TIAC =	$ 4,609,485
	TOTAL ANNUALIZED COSTS (TAC)					TAC = (TDAC) + (TIAC) =	$ 5,889,642

Cost Effectiveness Summary

TOTAL TONS NOx AVOIDED PER YEAR	=	207.2
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 28,425

Data Inputs for Capital Recovery Factor and Sinking Fund Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years
Catalyst Life	2	years
Asset Utilization	100	%

Table 3-6. UAF - Capital Costs for SNCR on the Large CFB Coal-fired Boiler (EU ID 113)

Shaded cells indicate user inputs.

Total Capital Investment Determination - SNCR

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 113 - CFB Boiler)

Date: 2/3/2016
Prepared By: L. Pacini
Checked By: C. Stevenson
Rev: A

Capital Costs

DIRECT COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1)	**Purchased equipment and material costs**							
(a)	**Basic equipment**							
	Total DSI System	1	EA	1,000,000	$ 1,000,000			
	(per Babcock & Wilcox)						**TOTAL =**	**$ 1,000,000**
(b)	**Instrumentation**							
	Total Instrumentation		EA		$ -			
							TOTAL =	**$ -**
(c)	**Freight**							
	SNCR Freight		% MATL COST	0%		$ -		
							TOTAL =	**$ -**
(d)	**Labor**							
	Labor - offsite fab		MH			$ -		
	Labor - onsite		MH			$ -		
							TOTAL =	**$ -**
(e)	**Vendor representatives fees**							
	Fab Site Vendor Representatives fees (enter no. of days and daily rate)		Days			$ -		
	Onsite Vendor Representatives fees (enter no. of days and daily rate)		Days			$ -		
							TOTAL =	**$ -**
Purchased Equipment and Material Cost (PEMC)		All above costs included in vendor scope.					PEMC =	**$ 1,000,000**
(2)	**Direct Installation Costs**							
(a)	**Concrete**		CY		$ -			$ -
(b)	**Piling**		TON		$ -			$ -
(c)	**Structural steel**		TON		$ -			$ -
(d)	**Electrical**		LOT		$ -			$ -
(e)	**Painting**		SF		$ -			$ -
(f)	**Insulation**		LOT		$ -			$ -
(g)	**Abovegrade piping**		LF		$ -			$ -
(h)	**Functional Checkouts**							
	Functional Checkout - fab site, enter %:		% offsite fab labor			$ -		$ -
	Functional Checkout - onsite, enter %		% onsite fab labor			$ -		$ -
	Contractor Commissioning, enter %:		% of equipment total cost			$ -		$ -
Direct Installation Costs (DIC) - 1 x SNCR Equipment Capital							DIC =	**$ 1,000,000**
Total Direct Costs (TDC)							TDC = (PEMC) + (DIC) =	**$ 2,000,000**
INDIRECT COSTS								
(3)	Engineering, Procurement & Construction Support Services	18%	% TDC			$ 360,000		
(4)	Performance tests		EA			$ -		
Total Indirect Costs (TIC)							TIC =	**$ 360,000**
MANAGEMENT AND CONTINGENCY COSTS								
(5)	Unit Operator Costs		% TDC					Excluded in this estimate.
(6)	Contingency	30%	% TDC			$ 600,000		
Total Management and Contingency Costs (TM&CC)							TM & CC =	**$ 600,000**
TOTAL CAPITAL INVESTMENT (TCI)							TCI = (TDC)+(TIC)+(TM&CC) =	**$ 2,960,000**

Table 3-7. UAF - Annualized Costs for SNCR on the Large CFB Coal-fired Boiler (EU ID 113)

Shaded cells indicate user inputs

Total Capital Investment Determination - SNCR

Project:	UAF - $PM_{2.5}$ BACT Analysis (EU ID 113 - CFB Boiler)
Date:	2/3/2016
Prepared By:	L. Pacini
Checked By:	C. Stevenson
Rev:	A

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating Labor		MH		-	Excluded	Excluded
(2)	Supervisory Labor		MH		-	Excluded	Excluded
(3)	Maintenance Labor		MH		-	Excluded	Excluded
(4)	Maintenance Materials		LOT		Excluded	-	Excluded
(5)	Utilities						
(a)	Aqueous Ammonia:	87.60	TON	200.08	$ 17,527		$ 17,527
(b)	Electricity: (per Babcock & Wilcox)		KWH	0.18	$ -		$ -
Total Direct Annual Costs (TDAC)						TDAC =	$ 17,527
INDIRECT ANNUAL COSTS							
(6)	Overhead		%		Excluded	$ -	$ -
(7)	Administrative Charges and Insurance	3.00%	% total capital			$ 88,800	$ 88,800
	Capital Recovery Factor [see inputs below]	0.1424					
(8)	Capital Recovery					CRF * TCI =	$ 421,437
Total Indirect Annual Costs (TIAC)						TIAC =	$ 510,237
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 527,764

Cost Effectiveness Summary

TOTAL TONS NOx AVOIDED PER YEAR	=	51.78
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 10,192

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 3-8. UAF - Capital Costs for SCR on the Mid-sized Diesel Boiler (EU ID 3)

Shaded cells indicate user inputs.

Total Capital Investment Determination - SCR

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 3 - Zurn Boiler)

Date: 2/17/2016
Prepared By: L. Pacini
Checked By: J. Rubino
Rev: C

Capital Costs

DIRECT COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1)	**Purchased equipment and material costs**							
(a)	**Basic equipment**							
	Total SCR System	1	EA	850000	$ 850,000			
	(per Fuel Tech)						TOTAL = $	850,000
(b)	**Instrumentation**							
	NOx CEMs System	1	EA	50000	$ 50,000			
	NOx CEMS Certification Testing	1	EA	10000	$ 10,000			
							TOTAL = $	60,000
(c)	**Freight**							
	SCR Freight	1		20,000				
							TOTAL = $	20,000
(d)	**Labor**							
	Labor - shop fab		MH			Included above		
	Labor - onsite		MH			Included above		
							TOTAL = $	-
(e)	**Startup Spares**							
	Startup Spare Parts for SCR	0.50%	%		$ 4,250			
							TOTAL = $	4,250
(f)	**Vendor representatives fees**							
	Fab Site Vendor Representatives fees (enter no. of days and daily rate)		Days			Included above		
	Onsite Vendor Representatives fees (enter no. of days and daily rate)		Days			Included above		
							TOTAL = $	-
Purchased Equipment and Material Cost (PEMC)		All above costs included in vendor scope.					PEMC =	934,250
(2)	**Direct Installation Costs**							
(a)	**Concrete**		CY		$ -		$	-
(b)	**Piling**		TON		$ -		$	-
(c)	**Structural steel**		TON		$ -		$	-
(d)	**Electrical**		LOT		$ -		$	-
(e)	**Painting**		SF		$ -		$	-
(f)	**Insulation**		LOT		$ -		$	-
(g)	**Abovegrade piping**		LF		$ -		$	-
(h)	**Functional Checkouts**							
	Functional Checkout - fab site, enter %:		% offsite fab labor				$	-
	Functional Checkout - onsite, enter %		% onsite fab labor				$	-
	Contractor Commissioning, enter %:		% of equipment total cost			$ -	$	-
Direct Installation Costs (DIC) - 2 x SCR Equipment Capital							DIC =	1,700,000
Total Direct Costs (TDC)							TDC = (PEMC) + (DIC) =	2,634,250
INDIRECT COSTS								
(3)	Engineering, Procurement & Construction Support Services		% TDC			$ -		Included in PEMC above.
(4)	Performance tests	1	EA	10,000		$ 10,000		
Total Indirect Costs (TIC)							TIC =	10,000
MANAGEMENT AND CONTINGENCY COSTS								
(5)	Unit Operator Costs		% TDC					Excluded in this estimate.
(6)	Contingency	30%	% TDC			$ 790,275		
Total Management and Contingency Costs (TM&CC)							TM & CC =	790,275
TOTAL CAPITAL INVESTMENT (TCI)							TCI = (TDC)+(TIC)+(TM&CC) =	3,434,525

Table 3-9. UAF - Annualized Costs for SCR on the Mid-sized Diesel Boiler (EU ID 3)

Shaded cells indicate user inputs

Cost Effectiveness Determination - SCR

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 3 - Zurn Boiler)

Date: 2/17/2016
Prepared By: L. Pacini
Checked By: J. Rubino
Rev: C

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating Labor	730	MH	105		$ 76,650	$ 76,650
(2)	Supervisory Labor	183	MH	125		$ 22,813	$ 22,813
(3)	Maintenance Labor	365	MH	105		$ 38,325	$ 38,325
(4)	Maintenance Materials		LOT		excluded in this estimate		
(5)	Utilities						
	(a) Urea Solution:	15.57	TON	356	$ 5,544		$ 5,544
	(50% Urea solution and 2.2 moles needed per ton of NOX removed.)						
	(b) Energy:	376680	kWh	0.18	$ 67,802		$ 67,802
(6)	Annual RATA Testing	1	EA	10,000	$ 10,000		$ 10,000
(7)	Catalyst Replacement Costs (every 2 years)						
	(per FuelTech)						
	(a) Replacement of SCR Catalyst: % of total equipment cost	30%	% total equip	$ 934,250	$ 280,275.00		$ 135,399
	(per MiraTech)						
	(b) Replacement labor for SCR Catalyst	180	MH	105		$ 18,900	$ 9,130
	(c) Transport cost direct to site (SCR catalyst)	13%	% replacement			36,436	$ 17,602
	(d) Transport cost for spent SCR catalyst	13%	% replacement			$ 36,436	$ 17,602
Sinking Fund Factor [see inputs below]:		0.4831					
Total Direct Annual Costs (TDAC)						TDAC =	$ 400,867
INDIRECT ANNUAL COSTS							
(8)	Overhead		%		excluded in this estimate	$ -	$ -
(9)	Administrative Charges and Insurance	3.00%	% total capital			$ 103,036	$ 103,036
	Capital Recovery Factor [see inputs below]	0.1424					
(10)	Capital Recovery					CRF * TCI =	$ 488,999
Total Indirect Annual Costs (TIAC)						TIAC =	$ 592,035
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 992,901

Cost Effectiveness Summary

TOTAL TONS NOx AVOIDED PER YEAR	=	117.98
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 8,416

Data Inputs for Capital Recovery Factor and Sinking Fund Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years
Catalyst Life (from vendor)	2	years
Asset Utilization	100	%

Table 3-10. UAF - Capital Costs for LNB/FGR on the Mid-sized Diesel Boiler (EU ID 3)

Total Capital Investment Determination - Low NO_X Burners & FGR

Project: UAF $PM_{2.5}$ BACT Analysis - Zurn Boiler #3 (EU ID 3)

Date: 4/12/2016
Prepared By: L. Pacini
Checked By: J. Rubino
Rev: C

Capital Costs

DIRECT COSTS	QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1) Purchased equipment and material costs							
(a) Basic equipment							
Low NOx Burner	1	EA	419484	$ 419,484			
FGR FD Fans	1	EA	198872	$ 198,872		TOTAL =	$ 618,356
(from Indeck)							
(b) Instrumentation							
Total Instrumentation		EA		$ -	Included in above price		
						TOTAL =	$ -
(c) Freight							
		% MATL COST	10%		$ 61,835.60		
						TOTAL =	$ 61,836
(d) Labor							
Labor - offsite fab	0	MH		None required	$ -		
Labor - onsite	30	MH	$ 105		$ 3,150		
(from Indeck)						TOTAL =	$ 3,150
(e) Vendor representatives fees							
Fab Site Vendor Representatives fees	0	MH		None required	$ -		
Onsite Vendor Representatives fees	46	MH	$ 224		$ 10,290		
Onsite Vendor Representatives Travel & Expenses	1	EA	3500	$ 3,500			
(from Indeck)						TOTAL =	$ 13,790
Purchased Equipment and Material Cost (PEMC)						PEMC =	$ 697,132
Direct Installation Costs (DIC)						DIC =	$ 340,948
Total Direct Costs (TDC)						TDC = (PEMC) + (DIC) =	$ 1,038,079
INDIRECT COSTS							
(2) Engineering, Procurement & Construction Support Services	10%	% TDC			$ 103,808		
(3) Performance tests for NO_X emissions	1	EA	10000		$ 10,000		Excluded in this estimate.
Total Indirect Costs (TIC)						TIC =	$ 113,808
MANAGEMENT AND CONTINGENCY COSTS							
(4) Unit Operator Costs		% TDC					Excluded in this estimate.
(5) Contingency	10%	% TDC			$ 103,808		
Total Management and Contingency Costs (TM&CC)						TM & CC =	$ 103,808
TOTAL CAPITAL INVESTMENT (TCI)						TCI = (TDC)+(TIC)+(TM&CC) =	$ 1,255,695

Table 3-11. UAF - Annualized Costs for LNB/FGR on the Mid-sized Diesel Boiler (EU ID 3)

Shaded cells indicate user inputs

Cost Effectiveness Determination - Low NO_X Burners & FGR

Project:	UAF $PM_{2.5}$ BACT Analysis - Zurn Boiler #3 (EU ID 3)
Date:	4/12/2016
Prepared By:	L. Pacini
Checked By:	J. Rubino
Rev:	C

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating Labor - Not required		MH			$ -	$ -
(2)	Supervisory Labor - Not required		MH			$ -	$ -
(3)	Maintenance Labor - Not required		MH			$ -	$ -
(4)	Maintenance Materials - Not required		LOT		$ -	$ -	$ -
Total Direct Annual Costs (TDAC)						TDAC =	$ -
INDIRECT ANNUAL COSTS							
(5)	Overhead		MH		Excluded in this estimate.	$ -	$ -
(6)	Administrative Charges and Insurance	3.00%	% total capital			$ 37,671	$ 37,671
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					CRF * TCI =	$ 178,783
Total Indirect Annual Costs (TIAC)						TIAC =	$ 216,454
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 216,454

Cost Effectiveness Summary

TOTAL TONS AVOIDED PER YEAR	=	59.57
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 3,634

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years
Catalyst Life	N/A	years
Asset Utilization	N/A	%

Table 3-12. UAF - Capital Costs for LNB/FGR on the Mid-sized Diesel Boiler (EU ID 4)

Shaded cells indicate user inputs.

Total Capital Investment Determination - Low NO_X Burners & FGR

Project:	UAF $PM_{2.5}$ BACT Analysis - Zurn Boiler (EU ID 4)
Date:	3/18/2016
Prepared By:	L. Pacini
Checked By:	J. Rubino
Rev:	A

Capital Costs

DIRECT COSTS	QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1) Purchased equipment and material costs							
(a) Basic equipment							
Low NOx Burner	1	EA	444039	$ 444,039			
FGR FD Fans	1	EA	187755	$ 187,755		TOTAL =	$ 631,794
(b) Instrumentation							
Total Instrumentation		EA		$ -	Included in above price		
						TOTAL =	$ -
(c) Freight							
		% MATL COST	10%		$ 44,404		
						TOTAL =	$ 44,404
(d) Labor							
Labor - offsite fab	0	MH		None required	$ -		
Labor - onsite	0	MH	$ -		$ -		
						TOTAL =	$ -
(e) Vendor representatives fees							
Fab Site Vendor Representatives fees (enter no. of days and daily rate)	0	Days			$ -		
Onsite Vendor Representatives fees (enter no. of days and daily rate)	0	Days			$ -		
						TOTAL =	$ -
Purchased Equipment and Material Cost (PEMC)						PEMC =	$ 676,198
Direct Installation Costs (DIC)						DIC =	$ 442,659
Total Direct Costs (TDC)						TDC = (PEMC) + (DIC) =	$ 1,118,857
INDIRECT COSTS							
(2) Engineering, Procurement & Construction Support Services	10%	% TDC			$ 111,886		
(3) Performance tests		EA			$ -	Excluded in this estimate.	
Total Indirect Costs (TIC)						TIC =	$ 111,886
MANAGEMENT AND CONTINGENCY COSTS							
(4) Unit Operator Costs		% TDC				Excluded in this estimate.	
(5) Contingency	10%	% TDC			$ 111,886		
Total Management and Contingency Costs (TM&CC)						TM & CC =	$ 111,886
TOTAL CAPITAL INVESTMENT (TCI)						TCI = (TDC)+(TIC)+(TM&CC) =	$ 1,342,628

Table 3-13. UAF - Annualized Costs for LNB/FGR on the Mid-sized Diesel Boiler (EU ID 4)

Shaded cells indicate user inputs

Cost Effectiveness Determination - Low NO_X Burners & FGR

Project:	UAF $PM_{2.5}$ BACT Analysis - Zurn Boiler (EU ID 4)
Date:	3/18/2016
Prepared By:	L. Pacini
Checked By:	J. Rubino
Rev:	A

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating Labor		MH			$ -	$ -
(2)	Supervisory Labor		MH			$ -	$ -
(3)	Maintenance Labor		MH			$ -	$ -
(4)	Maintenance Materials		LOT		$ -	$ -	$ -
Total Direct Annual Costs (TDAC)		Excluded in this estimate				TDAC =	$ -
INDIRECT ANNUAL COSTS							
(5)	Overhead		MH		Excluded in this estimate.	$ -	$ -
(6)	Administrative Charges and Insurance	3.00%	% total capital			$ 40,279	$ 40,279
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					CRF * TCI =	$ 191,160
Total Indirect Annual Costs (TIAC)						TIAC =	$ 231,439
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 231,439

Cost Effectiveness Summary

TOTAL TONS AVOIDED PER YEAR	=	1.22
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 189,312

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years
Catalyst Life	N/A	years
Asset Utilization	N/A	%

Table 3-14. UAF - Capital Costs for SCR on the Large Diesel-Fired Engine (EU ID 8)

Shaded cells indicate user inputs

Total Capital Investment Determination - SCR

Project: UAF - PM2.5 BACT Analysis (EU ID 8 - Peaking/Backup Generator Engine)

Date: 10/13/2016
Prepared By: J. Rubino
Checked By: L. Pacini
Rev: A

Capital Costs

DIRECT COSTS	QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1) Purchased equipment and material costs							
(a) Basic equipment							
Total SCR System	1	EA	$2,842,107.84	$ 2,842,108			
						TOTAL = $	2,842,108
(b) Instrumentation							
NOx CEMs System		EA		$ -			
NOx CEMS Certification Testing		EA		$ -			
						TOTAL = $	-
(c) Freight							
SCR Freight							
						TOTAL = $	-
(d) Labor							
Labor - shop fab		MH					
Labor - onsite		MH					
						TOTAL = $	-
(e) Startup Spares							
Startup Spare Parts for SCR		%		$ -			
						TOTAL = $	-
(f) Vendor representatives fees							
Fab Site Vendor Representatives fees (enter no. of days and daily rate)		Days					
Onsite Vendor Representatives fees (enter no. of days and daily rate)		Days					
						TOTAL = $	-
Purchased Equipment and Material Cost (PEMC)	Note: Although existing SCR to be used, capital costs needed for catalyst replacement costs.					PEMC =	2,842,108
(2) Direct Installation Costs							
(a) Concrete		CY		$ -		$	-
(b) Piling		TON		$ -		$	-
(c) Structural steel		TON		$ -		$	-
(d) Electrical		LOT		$ -		$	-
(e) Painting		SF		$ -		$	-
(f) Insulation		LOT		$ -		$	-
(g) Abovegrade piping		LF		$ -		$	-
(h) Functional Checkouts							
Functional Checkout - fab site, enter %:		% offsite fab labor				$	-
Functional Checkout - onsite, enter %		% onsite fab labor				$	-
Contractor Commissioning, enter %:		% of equipment total cost			$ -	$	-
Direct Installation Costs (DIC)	Note: Although existing SCR to be used, capital costs needed for catalyst replacement costs.					DIC =	5,684,216
Total Direct Costs (TDC)						TDC = (PEMC) + (DIC) =	8,526,324
INDIRECT COSTS							
(3) Engineering, Procurement & Construction Support Services		% TDC		N/A	$ -		
(4) Performance tests		EA		N/A	$ -		
Total Indirect Costs (TIC)						TIC =	-
MANAGEMENT AND CONTINGENCY COSTS							
(5) Unit Operator Costs		% TDC					Excluded in this estimate.
(6) Contingency		% TDC		N/A	$ -		
Total Management and Contingency Costs (TM&CC)						TM & CC =	-
TOTAL CAPITAL INVESTMENT (TCI)						TCI = (TDC)+(TIC)+(TM&CC) =	8,526,324

Table 3-15. UAF - Annualized Costs for SCR on the Large Diesel-Fired Engine (EU ID 8)

Shaded cells indicate user inputs

Cost Effectiveness Determination - SCR

Project: UAF - PM2.5 BACT Analysis (EU ID 8 - Peaking/Backup Generator Engine)	Date: 10/13/2016
	Prepared By: J. Rubino
	Checked By: L. Pacini
	Rev: A

Annualized Costs

DIRECT ANNUAL COSTS			QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		TOTAL
(1)	Operating Labor		730	MH	105		$ 76,650		$ 76,650
(2)	Supervisory Labor		183	MH	125		$ 22,813		$ 22,813
(3)	Maintenance Labor		365	MH	105		$ 38,325		$ 38,325
(4)	Maintenance Materials			LOT		excluded in this estimate			
(5)	Utilities								
	(a)	Aqueous Ammonia	29.96	TON	200.08	$ 5,994			$ 5,994
	(b)	Energy:	69905	kWh	0.18	$ 12,583			$ 12,583
(6)	Annual RATA Testing		0	EA	10,000	$ -			$ -
(7)	Catalyst Replacement Costs (every 2 years)								
	(a)	Replacement of SCR Catalyst: % of total equipment cost	30%	% total equip	$ 2,842,108	$ 852,632.35			$ 411,900
	(b)	Replacement labor for SCR Catalyst	180	MH	105		$ 18,900		$ 9,130
	(c)	Transport cost direct to site (SCR catalyst)	13%	% replacement			110,842		$ 53,547
	(d)	Transport cost for spent SCR catalyst	13%	% replacement			$ 110,842		$ 53,547
Sinking Fund Factor [see inputs below]:			0.4831						
Total Direct Annual Costs (TDAC)								TDAC =	$ 684,489
INDIRECT ANNUAL COSTS									
(8)	Overhead			%		excluded in this estimate	$ -		$ -
(9)	Administrative Charges, Property Taxes, Insurance		3.00%	% total capital			$ 255,790		$ 255,790
	Capital Recovery Factor [see inputs below]		0.1424						
(10)	Capital Recovery							CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC)								TIAC =	$ 255,790
TOTAL ANNUALIZED COSTS (TAC)								TAC = (TDAC) + (TIAC) =	$ 940,278

Cost Effectiveness Summary

TOTAL TONS NOx AVOIDED PER YEAR	=	36
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 26,119

Data Inputs for Capital Recovery Factor and Sinking Fund Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years
Catalyst Life (from vendor)	2	years
Asset Utilization	100	%

Table 3-16. UAF - Capital Costs for SCR on the Small Diesel-Fired Engine (EU ID 27)

Shaded cells indicate user inputs.

Total Capital Investment Determination - SCR

Project:	UAF $PM_{2.5}$ BACT Analysis - ACEP Engine (EU ID 27)				Date:	12/18/2015
					Prepared By:	L. Pacini
					Checked By:	J. Rubino
					Rev:	D

Capital Costs

DIRECT COSTS	QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1) Purchased equipment and material costs							
(a) Basic equipment							
Total SCR System	1	EA	107120	$ 107,120			
(per NC Power Systems)						**TOTAL = $**	**107,120**
(b) Instrumentation							
Total Instrumentation		EA		$ -			
						TOTAL = $	**-**
(c) Freight							
SCR Freight			10500		$ 10,500		
(per NC Power Systems)						**TOTAL = $**	**10,500**
(d) Labor							
Labor - offsite fab		MH		Not included	$ -		
Labor - onsite	16	MH	$ 105.00		$ 1,680		
						TOTAL = $	**1,680**
(e) Startup Spares							
Startup Spare Parts for SCR	0.5%	%		$ 535.60			
						TOTAL = $	**536**
(f) Vendor representatives fees							
Fab Site Vendor Representatives fees (enter no. of days and daily rate)		Days			$ -		
Onsite Vendor Representatives fees (enter no. of days and daily rate)		Days			$ -		
						TOTAL = $	**-**
Purchased Equipment and Material Cost (PEMC)						**PEMC =**	**119,836**
(2) Direct Installation Costs							
(a) Concrete		CY		$ -		$	-
(b) Piling		TON		$ -		$	-
(c) Structural steel		TON		$ -		$	-
(d) Electrical		LOT		$ -		$	-
(e) Painting		SF		$ -		$	-
(f) Insulation		LOT		$ -		$	-
(g) Abovegrade piping		LF		$ -		$	-
(h) Functional Checkouts							
Functional Checkout - fab site, enter %:		% offsite fab labor			$ -	$	-
Functional Checkout - onsite, enter %		% onsite fab labor			$ -	$	-
Contractor Commissioning, enter %:		% of equipment total cost			$ -	$	-
Direct Installation Costs (DIC) - estimated at 10% Purchased Equipment Cost						**DIC =**	**11,984**
Total Direct Costs (TDC)						**TDC = (PEMC) + (DIC) =**	**131,819**
INDIRECT COSTS							
(3) Engineering, Procurement & Construction Support Services	15%	% TDC			$ 19,773		
(4) Performance tests	0	EA			$ -		Excluded in this estimate.
Total Indirect Costs (TIC)						**TIC =**	**19,773**
MANAGEMENT AND CONTINGENCY COSTS							
(5) Unit Operator Costs		% TDC					Excluded in this estimate.
(6) Contingency		% TDC			$ -		Excluded in this estimate.
Total Management and Contingency Costs (TM&CC)						**TM & CC =**	**-**
TOTAL CAPITAL INVESTMENT (TCI)						**TCI = (TDC)+(TIC)+(TM&CC) =**	**151,592**

Table 3-17. UAF - Annualized Costs for SCR on the Small Diesel-Fired Engine (EU ID 27)

Shaded cells indicate user inputs

Cost Effectiveness Determination - SCR

Project: UAF $PM_{2.5}$ BACT Analysis - ACEP Engine (EU ID 27)

Date: 12/18/2015
Prepared By: L Pacini
Checked By: J. Rubino
Rev: D

Annualized Costs

			QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
DIRECT ANNUAL COSTS								
(1)	Operating Labor		61	MH	105		$ 6,388	$ 6,388
(2)	Supervisory Labor		91	MH	125		$ 11,406	$ 11,406
(3)	Maintenance Labor		183	MH	105		$ 19,163	$ 19,163
(4)	Maintenance Materials			LOT		excluded in this estimate		
(5)	Utilities							
	(a)	Urea/DEF:	39.76	TON	587	$ 23,341		$ 23,341
	(b)	Energy:		kW		excluded in this estimate		
(6)	Catalyst Replacement Costs (every 5 years)							
	(a)	Replacement of SCR Catalyst: % of total equipment cost (per Miratech)	30%	% total equip	$ 119,836	$ 35,950.68		$ 2,602
	(b)	Replacement labor for SCR Catalyst	8	MH	105		$ 840	$ 61
	(c)	Transport cost direct to site (Urea, SCR catalyst)		%		excluded in this estimate	$ -	$ -
	(d)	Transport cost for spent SCR catalyst		%		excluded in this estimate	$ -	$ -
Sinking Fund Factor [see inputs below]:			0.0724					
Total Direct Annual Costs (TDAC)							TDAC =	$ 62,960
INDIRECT ANNUAL COSTS								
(7)	Overhead			MH		excluded in this estimate	$ -	$ -
(8)	Administrative Charges			MH		excluded in this estimate	$ -	$ -
(9)	Property tax					excluded in this estimate		
(10)	Insurance					excluded in this estimate		
	Capital Recovery Factor [see inputs below]		0.1424					
(11)	Capital Recovery						CRF * TCI =	$ 21,583
Total Indirect Annual Costs (TIAC)							TIAC =	$ 21,583
TOTAL ANNUALIZED COSTS (TAC)							TAC = (TDAC) + (TIAC) =	$ 84,544

Cost Effectiveness Summary

TOTAL TONS NOx AVOIDED PER YEAR	=	6.93
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 12,200

Data Inputs for Capital Recovery Factor and Sinking Fund Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years
Catalyst Life	5	years
Asset Utilization	50	%

Table 3-18. UAF - NO_X BACT Cost Effectiveness Summary for Each Emission Unit Type

Control Technology Option	Total Installed Capital ($)	Annualized Capital Cost ($/year)	Annual O&M Cost ($/year)	Cost Effectiveness ($/ton NO_X removed)
Large Coal-fired Boiler (Emission Unit 113)				
SCR + (CFB with staged combustion)	$26,740,640	$5,889,642	$1,280,157	$28,425
SNCR + (CFB with staged combustion)	$2,960,000	$527,764	$17,527	$10,192
CFB with staged combustion	~	~	~	~
Mid-sized Boiler (EU ID 3)				
SCR	$3,434,525	$992,901	$400,867	$8,416
LNB/FGR[1]	$1,255,695	$216,454	~	$3,634
Good Combustion Practices	~	~	~	~
Mid-sized Boiler (EU ID 4)				
LNB/FGR	$1,342,628	$231,439	~	$189,312
Good Combustion Practices	~	~	~	~
Large Diesel-fired Engine (EU ID 8)				
SCR + (Turbocharger and Aftercooler + Limited Operation)	$8,526,324	$940,278	$684,489	$26,119
Turbocharger and Aftercooler + Limited Operation	~	~	~	~
Small Diesel-fired Engine (EU ID 27)				
SCR + (Turbocharger and Aftercooler + Federal Limit + Limited Operation)	$151,592	$84,544	$62,960	$12,200
Turbocharger and Aftercooler + Federal Limit + Limited Operation	~	~	~	~

Notes:
[1] If the cost effectiveness of a LNB/FGR system were based on the actual operation of EU ID 3 during the last five years, the cost effectiveness of LNB/FGR would be approximately $35,500 per ton of NO_X removed.

Table 3-19. UAF - Proposed NO_X BACT and Associated Emission Rate for Each Emission Unit Type

Emission Unit		Fuel	NO_X BACT	
ID	Description		Description	Emission Rate[1]
113	Large Boiler	Coal and Biomass	CFB with staged combustion	0.2 lb/MMBtu
3	Mid-sized Boiler	Diesel	Good Combustion Practices	0.2 lb/MMBtu
4	Mid-sized Boiler	Diesel	Limited Operation + Good Combustion Practices	0.2 lb/MMBtu
		Natural Gas	Limited Operation + Good Combustion Practices	140 lb/MMscf
19 through 21	Small Boilers	ULSD	Limited Operation	1.24 g/MMBtu
8	Large Engine	Diesel	Turbocharger and Aftercooler + Limited Operation	0.0195 g/hp-hr
27	Small Engine	ULSD	Turbocharger and Aftercooler + Federal Limit + Limited Operation	3.20 g/hp-hr
9A	Medical/Pathological Waste Incinerator	Waste	Good Combustion Practices + Limited Operation	3.56 lb/ton

Notes:
[1] Emissions are on a per unit basis.

4.0 $PM_{2.5}$ BACT Analysis

The emission units presented in Table 1-2 all require a $PM_{2.5}$ BACT analysis. These emission units include both combustion units and material handling units. The emission units reviewed in this section are:

- EU ID 113, a large CFB coal and biomass-fired boiler;
- EU IDs 3 and 4, mid-sized diesel-fired and dual-fired (diesel and natural gas-fired) boilers, respectively;
- EU IDs 19, 20, and 21, small diesel-fired boilers;
- EU ID 8, a large diesel-fired engine;
- EU ID 27, a small diesel-fired engine;
- EU ID 9A, a medical/pathological waste incinerator; and
- EU IDs 105, 107, 109 through 111, 114, and 128 through 130.

4.1 Available $PM_{2.5}$ Control Options

The following subsections provide technical summaries of identified $PM_{2.5}$ control technology options and the availability for each of the emission units. Identified control technologies were determined from a review of the RBLC from 2005 to August 24, 2015 for all possible emission controls technologies. If the RBLC had limited information, additional control technologies were identified that are typical for the emission units. The results from the RBLC review can be found in Appendix A.

4.1.1 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – $PM_{2.5}$ CONTROL OPTIONS

A review of CFB coal-fired boilers and biomass-fired boilers rated at more than 250 MMBtu/hr in the RBLC was completed for $PM_{2.5}$ control technologies. The identified control technologies include:

- Fabric Filters;
- Electrostatic Precipitator (ESP);
- Scrubber;
- Cyclones;
- Settling Chamber; and
- Good Combustion Practices.

Fabric Filters – Large CFB Boiler $PM_{2.5}$ Control Option

Fabric filters (typically a baghouse) operate by passing the flue gas through filters in which particle collection occurs through interception, inertial impaction, diffusion, gravitational settling, and electrostatic attraction mechanisms. As the particles collect on the filter, the pressure drop becomes critical and the filter “cake” must be removed during a cleaning cycle. The filter cake is removed via mechanical shaking, reverse air cleaning, or pulse-jet cleaning. The filter cake then drops by gravity into collection hoppers and the filters begins another collection cycle. Baghouses are shown to achieve particulate matter collection efficiencies of 90 to 99.9 percent in the RBLC on a wide range of particle size distributions and loadings. The EPA fact sheet for new fabric filter pulse units (EPA-452/F-03-025) indicates new fabric filter baghouses can achieve 99 to 99.9 percent particulate matter emission control. Fabric filters are sensitive to humid gas streams which can cause excessive pressure drop, bag binding, and failure, especially in environments with ambient temperatures commonly below freezing. The operational complexity and high costs associated with fabric filter technology makes this technology impracticable for smaller units with relatively low particulate matter emissions.

The RBLC lists numerous fabric filter applications on coal-fired boilers rated at more than 250 MMBtu/hr. A review of the RBLC entries for large biomass-fired boilers also shows that several of these boilers used fabric filter technology. Fabric filter technology is an available $PM_{2.5}$ control technology for large boilers and is being proposed by UAF to control particulate matter emissions from this large boiler.

ESP – Large CFB Boiler $PM_{2.5}$ Control Option

An ESP operates by introducing a charge on the particulate matter entrained in the exhaust stream. The charged particles are then attracted to oppositely charged collection plates. The particles are deposited on the plates and the strong electrostatic field inhibits re-entrainment. The collected particulate matter is removed by mechanical rappers or a water wash, and the removed particles are then gravity-fed into collection hoppers. An ESP collection efficiency is highly dependent on particle resistivity, but removal efficiencies of 90 to 99.9 percent are possible (EPA-452/F-03-028).

For large boilers solely firing wood or biomass, an ESP is often paired with cyclones to control the larger diameter particulate matter. An ESP is an available control technology for this large coal and biomass-fired boiler.

Scrubber – Large CFB Boiler $PM_{2.5}$ Control Option

The RBLC identified two scrubbers having particulate matter control on coal-fired boilers. One unit is clearly identified as a venturi wet scrubber and the other unit is generally identified as a conventional scrubber. Scrubbers remove air pollutants by inertial and diffusional interception. The theory of venturi scrubber operation is that the exhaust stream is accelerated through a 'throat' section that is built into the duct that forces the gas stream to accelerate as the duct narrows and then expands. As the gas enters the venturi throat, both gas velocity and turbulence increase. A scrubbing liquid is introduced into the gas stream either upstream of the throat, in the throat, or upwards against the gas flow in the throat. The scrubbing liquid is then atomized into small droplets by the turbulence in the throat and droplet-particle interaction is increased.

After the throat section of the venturi, the particulate matter has become entrained in the droplets and then the liquid droplets are separated from the exhaust stream by a cyclonic separator and/or a mist eliminator. Venturi scrubber collection efficiencies of particulate matter range from 70 to 99 percent, depending on the application. Collection efficiencies are generally higher for particulate matter of 0.5 to 5 microns in diameter (EPA-452/F-03-017). The use of a wet scrubber is an available control technology for the large boiler.

Cyclones – Large CFB Boiler $PM_{2.5}$ Control Option

Cyclones are used in industrial applications to remove particulate matter from exhaust flows and other industrial stream flows. Dirty air enters a cyclone tangentially and the centrifugal force moves the particulate matter against the cone wall. The air flows in a helical pattern from the top down to the narrow bottom before exiting the cyclone straight up the center and out the top. Large and dense particles in the stream flow are forced by inertia into the walls of the cyclone where the material then falls to the bottom of the cyclone and into a collection unit. Cleaned air then exits the cyclone either for further treatment or release to the atmosphere.

The narrowness of the cyclone wall and the speed of the air flow determine the size of particulate matter that is removed from the stream flow. Cyclones are most efficient at removing large particulate matter and are generally designed to control particulate matter of 10 microns in diameter (PM_{10}) and larger. Cyclones are especially useful in harsh environments, industrial environments, high dust load streams, and high temperature applications. Cyclones controlling $PM_{2.5}$ and smaller particles are expected to have collection efficiencies of 0 to 40 percent for conventional single cyclones and 20 to 70 percent for high efficiency single cyclones. Cyclone design is generally driven by a pressure-drop limitation, which is the reason for the large range of efficiencies for $PM_{2.5}$ collection. The smaller the particulate matter diameter is, the poorer the collection efficiency becomes (EPA-452-F-03-005). Cyclones are an available control technology for this application.

Settling Chamber – Large CFB Boiler $PM_{2.5}$ Control Option

Settling chambers appear only in the biomass-fired boilers RBLC inventory for particulate matter control (not $PM_{2.5}$ control) and not in the RBLC inventory for coal-fired boilers. This type of technology is a part of the group of air pollution controls collectively referred to as ‘pre-cleaners’ because the units are often used to reduce the inlet loading of particulate matter to downstream collection devices by removing the larger, abrasive particles. The principle behind particulate matter removal in a settling chamber is that the gas velocity of the effluent stream is reduced which allows for larger dust particulate to settle from the effluent stream by gravity. Settling chambers most effectively control particulate matter with diameters greater than 50 microns (EPA-452/F-03-009). The collection efficiency of settling chambers is typically less than 10 percent for PM_{10} and the collection efficiency will be much less than 10 percent for smaller particulate matter.

The EPA fact sheet for settling chambers (EPA-452/F-03-009) does not specify the $PM_{2.5}$ control efficiency. The collection efficiency for material four times larger in diameter, PM_{10}, is less than 10 percent. The control efficiency is decreased with smaller particulate matter diameter. For these reasons, and because no settling chamber control technologies are identified in the RBLC for $PM_{2.5}$, settling chamber control technology is not an available control technology for the large CFB boiler.

Good Combustion Practices – Large CFB Boiler $PM_{2.5}$ Control Option

Large boilers that implement good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining a boiler in peak operating condition is in the interest of the owner because the boiler lifespan will be optimized. Operating a boiler according to the manufacturer's recommendation will keep the boiler at the highest level of efficiency, reduce strain on the boiler, and optimize maintenance and operating costs.

In the RBLC review, a number of sources identified good combustion practices as the BACT determination for large coal-fired boilers. CFB boilers can reduce the particulate matter exhaust loading through complete combustion of the coal. Good combustion practices are an available control technology.

4.1.2 MID-SIZED DIESEL-FIRED BOILERS (EU IDs 3 AND 4) – $PM_{2.5}$ CONTROL OPTIONS

A review of the RBLC for mid-sized diesel-fired boilers with a rating between 100 and 250 MMBtu/hr (process code 12.220) showed no emission control technologies identified for particulate matter. The RBLC was also reviewed for particulate matter BACT determinations for large diesel-fired boilers rated at more than 250 MMBtu/hr (process code 11.220). Three BACT determinations were found in the RBLC for larger boilers. Only one entry identified an ESP as particulate matter control technology. A review of the RBLC for the past ten years was also conducted for mid-sized natural gas-fired boilers because EU ID 4 has the ability to burn natural gas. This review found good combustion practices and the use of natural gas as the only BACT determinations. Incorporating the control technologies identified for both diesel and natural gas-fired boilers, and including fabric filters and cyclone technology which are both proposed for the larger CFB coal-fired boiler, results in the following list of possible $PM_{2.5}$ control options:

- Fabric Filters:
- ESP;
- Scrubber;
- Cyclone;
- Natural Gas;
- Limited Operation; and
- Good Combustion Practices.

Fabric Filters – Mid-sized Diesel-fired Boilers $PM_{2.5}$ Control Option
As described above, fabric filters (typically a baghouse) operate by passing the flue gas through filters on which particle matter collection occurs through interception, inertial impaction, diffusion, gravitational settling, and electrostatic attraction mechanisms. As the collected particles collect on the filter, the pressure drop becomes critical and the filter "cake" is removed via mechanical shaking, reverse air cleaning, or pulse-jet cleaning. The dust then drops by gravity into collection hoppers and the filter begins another collection cycle. Baghouses can achieve particulate matter collection efficiencies of 95 percent or greater on a wide range of particle size distributions and loadings. Fabric filters are sensitive to humid gas streams which can cause excessive pressure drops, bag binding, and failure, especially in environments with ambient temperatures commonly below freezing. The operational complexity and high costs associated with fabric filter technology makes this technology impracticable for smaller units with relatively low particulate matter emissions.

SCI engineers indicated that particulate matter in the exhaust would be coated with unburned diesel fuel which would cause the particulate matter to plug the bags. The RBLC did not identify any applications of fabric filter technology to diesel-fired boilers with a rating of 100 MMBtu/hr or greater. Although fabric filters are not a common particulate matter control technology for mid-sized diesel-fired boilers, this technology is available.

ESP – Mid-sized Diesel-fired Boilers $PM_{2.5}$ Control Option
An ESP operates by introducing a charge on the particulate matter entrained in the exhaust stream. The charged particles are then attracted to oppositely charged collection plates. The particles are deposited on the plates and the strong electrostatic field inhibits re-entrainment. The collected particulate matter is removed by mechanical rappers or a water wash, and the removed particles are then gravity-fed into collection hoppers. ESP collection efficiency is highly dependent on particle resistivity, but removal efficiencies of 95 percent or greater are possible.

ESPs can have collection efficiencies that are similar fabric filters. A review of the RBLC did not identify any ESPs for BACT control of particulate matter for mid-sized diesel-fired boilers. Only one diesel-fired boiler rated at 995 MMBtu/hr was shown to be equipped with an ESP. This large boiler is more than five times the rated capacity of EU ID 3 and more than 50 times the restricted annual capacity of EU ID 4. Although an ESP is likely not to be an appropriate technology for these boilers, an ESP is an available technology for this analysis.

Scrubber – Mid-sized Diesel-fired Boilers $PM_{2.5}$ Control Option
The RBLC did not identify any scrubbers as control technology for diesel-fired or natural gas-fired boilers in this size range. Scrubbers remove air pollutants by inertial and diffusional interception. As described above, the theory of venturi scrubber operation is that the exhaust stream is accelerated through a 'throat' section that is built into the duct that forces the gas stream to accelerate as the duct narrows and then expands. As the gas enters the venturi

throat, both gas velocity and turbulence increase. The scrubbing liquid is introduced into the gas stream either upstream of the throat, in the throat, or upwards against the gas flow in the throat. The scrubbing liquid is atomized into small droplets by the turbulence in the throat and droplet-particle interaction is increased.

After the throat section of the venturi, the particulate matter has become entrained in the droplets and then the liquid droplets are separated from the exhaust stream by a cyclonic separator and/or a mist eliminator. Venturi scrubber collection efficiencies of particulate matter range from 70 to 99 percent, depending on the application (EPA-452/F-03-017). Scrubbers are an available control technology for these boilers.

Cyclone – Mid-sized Diesel-fired Boilers $PM_{2.5}$ Control Option

Cyclones are used in industrial applications to remove particulate matter from exhaust flows and other industrial stream flows as discussed above. Dirty air enters a cyclone tangentially and the centrifugal force moves the particulate matter against the cone wall. The air flows in a helical pattern from the top down to the narrow bottom before exiting the cyclone straight up the center and out the top. Large and dense particles in the stream flow are forced by inertia into the walls of the cyclone where the material then falls to the bottom of the cyclone and into a storage unit. Cleaned air then exits the cyclone either for further treatment or release to the atmosphere.

The narrowness of the cyclone wall and the speed of the air flow determine the size of particulate matter that is removed from the stream flow. Cyclones are most efficient at removing large particulate matter. Cyclones are especially useful in harsh environments, industrial environments, high dust load streams and high temperature applications. Cyclones controlling $PM_{2.5}$ and smaller particles are expected to have collection efficiencies of 0 to 40 percent for conventional single cyclones and 20 to 70 percent for high efficiency single cyclones. Cyclone design is generally driven by a pressure-drop limitation which is the reason for the large range of efficiencies for the $PM_{2.5}$. The smaller the particulate matter diameter is, the poorer the collection efficiency becomes (EPA-452/F-03-005).

Although a cyclone is likely not to be an appropriate technology for these boilers, a cyclone is an available technology for this analysis.

Natural Gas – Mid-sized Diesel-fired Boilers $PM_{2.5}$ Control Option

Although both EU IDs 3 and 4 are permitted to operate on natural gas, only EU ID 4 is equipped with the ability to operate on natural gas. Natural gas combustion has a lower particulate matter emission rate than diesel combustion, so natural gas can be a preferred fuel for this reason. The availability of natural gas in Fairbanks is limited. Natural gas must be trucked to Fairbanks because no pipeline currently supplies natural gas to Fairbanks. Although EU ID 4 is permitted for a 10 percent capacity factor which reduces the fuel usage significantly, natural gas is not a reasonable option for this boiler because natural gas is only available in limited quantities. EU ID 4 must retain the ability to burn diesel if natural gas is not available.

UAF has noticed a significant dip in gas supply pressure to EU ID 4 as load is increased. The gas supplier will likely not be able to maintain adequate pressure if both EU IDs 3 and 4 were operated at elevated loads while firing natural gas.

Due to the lack of a gas pipeline into Fairbanks and the experience of significant dips on pipeline pressure, the use of only natural gas as a control technology is not an available option for either EU ID 3 or 4. The remainder of this BACT analysis for EU ID 4 will focus on diesel operation because natural gas supply is limited.

Limited Operation – Mid-sized Boilers $PM_{2.5}$ Control Option

Limited operation is an available control technology for both EU IDs 3 and 4. EU ID 4 already has an enforceable operating restriction due to the permitted 10 percent capacity factor restriction. With fewer hours of operation, the annual potential $PM_{2.5}$ emissions are reduced. This approach is not always practical to $PM_{2.5}$ control because not all emission units can operated in a limited manner while sustaining the needed electricity and steam output commitments. Limited operation is an available BACT control for $PM_{2.5}$ emissions from the boilers.

Good Combustion Practices – Mid-sized Diesel-fired Boiler $PM_{2.5}$ Control Option

Mid-sized boilers following good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining a boiler in peak operating condition is in the interest of every owner because the boiler lifespan will be optimized. Operating a boiler according to the manufacturer's recommendation will keep the boiler at the highest level of efficiency, reduce fuel costs, reduce strain on the boiler, and optimize maintenance and operating costs.

Although the RBLC review did not identify good combustion practices as BACT for mid-sized diesel-fired boilers, good combustion practices was a common technology identified for natural gas-fired boilers. Good combustion practices are an available control technology for EU IDs 3 and 4.

4.1.3 SMALL DIESEL-FIRED BOILERS (EU IDS 19 THROUGH 21) – $PM_{2.5}$ CONTROL OPTIONS

The three small diesel-fired boilers share an hourly operating restriction of 19,650 hours per year. These boilers have no particulate matter emission controls. A review of the RBLC for small diesel-fired boilers rated at less than 100 MMBtu/hr (process code 13.220) identified one add-on emission control technology for particulate matter. This add-on control was a scrubber. The RBLC also identified good combustion practices as a control technology. Many determinations had no entry. The following list identifies possible $PM_{2.5}$ emission control options for consideration.

- Scrubber;

- Limit Operation; and
- Good Combustion Practices.

Scrubber – Small Diesel-fired Boilers $PM_{2.5}$ Control Option
The RBLC identified one scrubber, which could be wet or dry, for particulate matter control on a 90 MMBtu/hr boiler. As described above, scrubbers remove air pollutants by inertial and diffusional interception. The theory of venturi scrubber operation is that the exhaust stream is accelerated through a 'throat' section that is built into the duct that forces the gas stream to accelerate as the duct narrows and then expands. As the gas enters the venturi throat, both gas velocity and turbulence increase. The scrubbing liquid is introduced into the gas stream either upstream of the throat, in the throat, or upwards against the gas flow in the throat. The scrubbing liquid is atomized into small droplets by the turbulence in the throat and droplet-particle interaction is increased.

After the throat section of the venturi, the particulate matter has become entrained in the droplets and then the liquid droplets are separated from the exhaust stream by a cyclonic separator and/or a mist eliminator. Venturi scrubber collection efficiencies of particulate matter range from 70 to 99 percent, depending on the application (EPA-452/F-03-017). Scrubbers are an available control technology for the small boilers.

Limited Operation – Small Diesel-fired Boilers $PM_{2.5}$ Control Option
The three small boilers are currently sharing an hourly operating limit of 19,650 hours per year. With fewer available hours of operation, the annual potential $PM_{2.5}$ emissions are reduced. Limited operation is an available BACT control for these small boilers.

Good Combustion Practices – Small Diesel-fired Boilers $PM_{2.5}$ Control Option
Small boilers that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining a boiler in peak operating condition is in the interest of every owner because the boiler lifespan will be optimized. Operating a boiler according to the manufacturer's recommendation will keep the boiler at the highest level of efficiency, reduce fuel costs, reduce strain on the boiler, and optimize maintenance and operating costs.

The RBLC identified good combustion practices as BACT for many small diesel-fired boilers. Good combustion practices are an available control technology.

4.1.4 LARGE DIESEL-FIRED ENGINE (EU ID 8) – $PM_{2.5}$ CONTROL OPTIONS

The large diesel-fired engine has a positive crankcase ventilation system which acts as particulate matter emission control technology. EU ID 8 also has restricted operations because of the NO_X emission limit shared with EU ID 4. This limit also reduces potential $PM_{2.5}$ and other emissions. A review of the RBLC for large diesel-fired engines (process code 17.110) identified many control technologies for particulate matter emissions. In addition to the RBLC identified control options, use of a diesel particulate matter filter is considered. The following list identifies these possible $PM_{2.5}$ emission control options:

- Diesel Particulate Filter (DPF);
- Positive Crankcase Ventilation;
- Low Ash Diesel;
- Federal Standard;
- Limited Operation; and
- Good Combustion Practices.

DPF – Large Diesel-fired Engine $PM_{2.5}$ Control Option

Although a DPF is not a control technology identified by the RBLC search, DPF is a control technology that can reduce $PM_{2.5}$ emissions and will be considered available. DPF systems are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media once soot has become caked onto the media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. DPF is an available control option.

Positive Crankcase Ventilation – Large Diesel-fired Engine $PM_{2.5}$ Control Option

One engine in the RBLC (process code 17.110) identified positive crankcase ventilation as a $PM_{2.5}$ control option. Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject a second opportunity for combustion. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of combustion and reduce the thermal NO_X formation. Positive crankcase ventilation is part of the EU ID 8 engine design and is an available control technology.

Low Ash Diesel – Large Diesel-fired Engine $PM_{2.5}$ Control Option

Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. EU ID 8 is fired exclusively on distillate fuel which is a form of a refined fuel. The potential $PM_{2.5}$ emissions are based on emission factors for distillate fuel. EU ID 8 is capable of firing either diesel or heavy fuel oil (non-low ash fuel) according to manufacturer specifications. UAF only uses low ash distillate fuel in EU ID 8. Low ash diesel is an available control option.

Federal Standard – Large Diesel-fired Engine $PM_{2.5}$ Control Option
Multiple RBLC NO_X determinations identified that large engines are required to meet federal emission standards. The RBLC determinations indicated the engines were to meet the NSPS requirements of 40 CFR 60 Subpart IIII, NRE standards or EPA certification. Subpart IIII has performance standards for stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The age, rating and size of the compression cylinder will determine whether the applicable federal emission standard is in Subpart IIII, referenced to the NRE standards, or if the engine comes with a manufacturer's certification meeting the required federal standards.

EU ID 8 was installed in 1999 and has not been reconstructed since that time. As a result, the Subpart IIII emission standards cited in the RBLC are not applicable to EU ID 8 because the engine was installed before the applicability date. No other federal emission standards apply to engines the age of EU ID 8.

On this basis, complying with the federal emission standards is not an appropriate control option for EU ID 8 and will not be considered any further in this analysis.

Limited Operation – Large Diesel-fired Engine $PM_{2.5}$ Control Option
Many RBLC determinations identified limiting the engine operation as $PM_{2.5}$ emission control. With fewer available hours of operation, the annual potential $PM_{2.5}$ emissions are reduced. This approach is not always practical because not all emission units can be operated in a limited manner while sustaining the needed electrical output. EU ID 8 has an operating restriction because the engine shares a NO_X emission limit with EU ID 4. Although the operating restriction is for NO_X, this restriction limits emissions of other pollutants, including $PM_{2.5}$. Limited operation is an available BACT control for $PM_{2.5}$ emissions from the large engine.

Good Combustion Practices – Large Diesel-fired Engine $PM_{2.5}$ Control Option
Large engines that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining an engine in peak operating condition is in the interest of the owner because the engine lifespan is optimized. Operating an engine according to the manufacturer's recommendation will keep the engine at the highest level of efficiency, lower fuel costs, reduce strain on the engine, and optimize maintenance and operating costs.

Good combustion practices are an available control technology.

4.1.5 SMALL DIESEL-FIRED ENGINE (EU ID 27) – $PM_{2.5}$ CONTROL OPTIONS

EU ID 27 is a small certified Tier 3 diesel-fired engine with an operating limit of 4,390 hours per year. The review of similar engines in the RBLC (process code 17.210) includes several control technologies for particulate matter emissions. The following list identifies these possible $PM_{2.5}$ control options:

- DPF;
- Federal Standard;
- Limited Operation; and
- Good Combustion Practices.

DPF – Small Diesel-fired Engine $PM_{2.5}$ Control Option
Although DPF is not a control technology identified by the RBLC search, DPF is a control technology that can reduce $PM_{2.5}$ emissions. DPF is designed to physically filter particulate matter from the exhaust stream. Several designs are available which can either require cleaning and replacement of the filter media once soot becomes caked onto the media. Regenerative filter designs are available that burn-off the caked-on soot on a regular basis to regenerate the filter media.

DPF can reduce particulate emissions by 85 percent or more according to SCI. DPF is an available control technology.

Federal Standard – Small Diesel-fired Engine $PM_{2.5}$ Control Option
Several RBLC $PM_{2.5}$ determinations identified small engines being required to meet federal emission standards. The RBLC determinations indicated the engines were to meet the requirements of 40 CFR 60 Subpart IIII, NRE standards, or EPA certification requirements. Subpart IIII has performance standards for stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The age, rating, and size of the compression cylinder determines whether the applicable federal emission standard is in Subpart IIII, referenced to the NRE standards, or if the engine comes with a manufacturer's certification of meeting the required federal standards.

EU ID 27 was recently manufactured and installed. The unit is a certified Tier 3 engine. As a result, complying with the applicable federal emission standards is an available control option.

Limited Operation – Small Diesel-fired Engine $PM_{2.5}$ Control Option
Only a few RBLC determinations identified limiting the engine operation as the $PM_{2.5}$ control option. With fewer hours of operation, the annual potential $PM_{2.5}$ emissions are reduced. This approach is not always practical to control $PM_{2.5}$ emissions because not all emission units can be operated in a limited manner while sustaining electricity output commitments.

EU ID 27 is subject to a 4,380 hours per year operating limit. As a result, limited operation is an available control option.

Good Combustion Practices – Small Diesel-fired Engine $PM_{2.5}$ Control Option
Small engines that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining an engine in peak operating condition is in the interest of every owner because the engine lifespan will be optimized. Operating an engine according to the manufacturer's recommendation will keep the engine at the highest level of efficiency, lower fuel costs, reduce strain on the engine, and optimize maintenance and operating costs.

Good combustion practices are an available control technology and are standard practice, as well as a component of compliance with applicable federal emission standards.

4.1.6 MEDICAL/PATHOLOGICAL WASTE INCINERATOR (EU ID 9A) – $PM_{2.5}$ CONTROL OPTIONS

The medical/pathological waste incinerator is restricted to processing no more than 109 tons of waste per year and operates with a secondary combustion chamber. A review of the RBLC for similar hospital, medical and infectious waste incinerators (process code 21.300) identified only the use of multiple combustion chambers for particulate matter control technology, yet the following list identifies several additional $PM_{2.5}$ control options:

- Fabric Filters;
- ESP;
- Limited Operation;
- Good Combustion Practices; and
- Multiple Chambers.

Fabric Filters – Medical/Pathological Waste Incinerator $PM_{2.5}$ Control Option
Fabric filters (typically a baghouse) operate by passing the flue gas through filters on which particle collection occurs through interception, inertial impaction, diffusion, gravitational settling, and electrostatic attraction mechanisms. As the collected particles accumulate on the filter, the pressure drop becomes critical and the filter "cake" is removed via mechanical shaking, reverse air cleaning, or pulse-jet cleaning. The dust then drops by gravity into collection hoppers and the filter begins another collection cycle. Baghouses can achieve particulate matter collection efficiencies of 95 percent or greater on a wide range of particle size distributions and loadings. Fabric filters are sensitive to humid gas streams which can cause excessive pressure drops, bag binding, and failure, especially in environments with ambient temperatures commonly below freezing.

The operational complexity and high costs associated with fabric filter technology makes this technology impractical for small units with relatively low particulate matter emissions. SCI indicated that particulate matter in the exhaust would be coated with unburned fuel which could cause the particulate matter to plug the bags. The RBLC did not identify any applications of fabric filter technology for incinerators. Although fabric filters are not a common particulate matter control technology for similar incinerators, this technology is available.

ESP – Medical/Pathological Waste Incinerator $PM_{2.5}$ Control Option
As described above, an ESP operates by introducing a charge on the particulate matter entrained in an exhaust stream. The charged particles are then attracted to oppositely charged collection plates. The particles are deposited on the plates and the strong electrostatic field inhibits re-entrainment. The collected particulate matter is removed by mechanical rappers or a water wash, and the removed particles are then gravity-fed into collection hoppers. ESP collection efficiency is highly dependent on particle resistivity, but removal efficiencies of 95 percent or greater are possible. ESPs can have collection efficiencies similar to fabric filter collection efficiencies.

A review of the RBLC did not identify any ESPs for BACT control of particulate matter from similar incinerators. Although ESPs are not a common particulate matter emission control technology for pathological waste incinerators, ESPs are an available control technology.

Multiple Chambers – Medical/Pathological Waste Incinerator $PM_{2.5}$ Control Option
One RBLC entry for hospital, medical and infectious waste incinerators was found from a review of the last ten years. The identified control technology for this incinerator was multiple chambers. A multiple chamber incinerator introduces the waste material and a portion of the combustion air in the primary chamber. The waste material is combusted in the primary chamber. The secondary chamber introduces the remaining air to complete the combustion of all incomplete combustion products. Many of the volatile organic compounds from waste material are completely combusted in the secondary chamber. An EPA fact sheet indicates that solid waste incinerators can reduce PM_{10} emissions up to 70 percent (EPA-452/F03-022) using multiple chambers. The expectation is that less than 70 percent control of $PM_{2.5}$ would be obtained. The incinerator has a multiple chamber design, so multiple chambers are an available control technology.

Good Combustion Practices – Medical/Pathological Incinerator $PM_{2.5}$ Control Option
Incinerators that follow good combustion practices are maintained and operated according to manufacturer instructions and conventional industry practices. Maintaining an incinerator in good operating conditions is in the interest of every owner because the incinerator lifespan will be optimized and the highest level of destruction of pathological material is enabled. Good combustion practices are an available control technology.

Limited Operation – Medical/Pathological Incinerator $PM_{2.5}$ Control Option
While the RBLC did not identify limited operation as a $PM_{2.5}$ control option, fewer available hours of operation does reduce the annual potential $PM_{2.5}$ emissions. EU ID 9A is limited to 109 tpy of waste combustion. As a result, limited operation is an available control option.

4.1.7 MATERIAL HANDLING EMISSION UNITS (EU IDs 105, 107, 109 THROUGH 111, 114, AND 128 THROUGH 130) – $PM_{2.5}$ CONTROL OPTIONS

A review of the RBLC for several types of material handling sources was conducted. Coal handling (RBLC Process ID: 90.011), lime/limestone handling (RBLC Process ID: 90.019) and ash handling (RBLC 99.120) all take place at UAF, so each of these processes were reviewed for $PM_{2.5}$ control options. The control technologies identified in the RBLC include:

- Fabric Filters;
- Scrubber;
- Suppressant;
- Enclosure;
- Screens; and
- Closed System Vents/Negative Pressure Vents.

EU IDs 105, 107, 109, 110, 114, and 128 through 130 are controlled $PM_{2.5}$ emission units. These material handling units are enclosed and the emissions are vented through fabric filters before exhausting to the atmosphere. EU ID 111, the ash unloading to disposal trucks, occurs in a building which has large doors for allowing the haul trucks to arrive and leave. During ash unloading these doors remain closed to prevent the release of fugitive emissions and the potential generation of wind caused emissions.

Fabric Filters – Material Handling Emission Units $PM_{2.5}$ Control Option
Fabric filters operate by passing particulate laden air streams through filters on which particle collection occurs through interception, inertial impaction, diffusion and electrostatic attraction mechanisms. Fabric filters are sensitive to humid gas streams which can cause excessive pressure drops, filter binding, and failure, especially in environments with ambient temperatures commonly below freezing.

The RBLC review found that the use of fabric filters was the most common particulate matter technology used for control emissions from ash, coal and lime/limestone handling operations. Control efficiencies listed in the RBLC for fabric filter particulate matter control the efficiency were consistently 99 percent or better.

Fabric filter technology is considered an available $PM_{2.5}$ control technology for EU IDs 105, 107, 109, 110, 114, and 128 through 130 which currently have or are planned to be constructed with fabric filter dust collectors. EU ID 111 is the only material handling system without fabric filtration control because the emissions do not always occur in an enclosed building. The location at which ash is loaded into haul trucks is enclosed during the loading operation, but because large doors are opened to allow the trucks to enter and leave, any control technology would not service all the building air because much of the building air is exchanged with ambient air during the trucks departure. For this reason, a fabric filter is not an available control technology for EU ID 111.

Scrubber – Material Handling Emission Units $PM_{2.5}$ Control Option
The RBLC identified two scrubbers as particulate matter control for ash handling. Scrubbers remove air pollutants by inertial and diffusional interception. Several scrubber designs are available on the market that include high energy venturi designs and low energy spray tower design. The theory of venturi scrubber operation is that the exhaust stream is accelerated through a 'throat' section that is built into the duct that forces the gas stream to accelerate as the duct narrows and then expands. As the gas enters the venturi throat, both gas velocity and turbulence increase. The scrubbing liquid is introduced into the gas stream either upstream of the throat, in the throat, or upwards against the gas flow in the throat. The scrubbing liquid is then atomized into small droplets by the turbulence in the throat and droplet-particle interaction is increased.

After the throat section of the venturi, the particulate matter has become entrained in the droplets and then the liquid droplets are separated from the exhaust stream by a cyclonic separator and/or a mist eliminator. Venturi scrubber collection efficiencies of particulate matter range from 70 to 99 percent, depending on the application (EPA-452/F-03-017).

In a spray tower design scrubber, the spray mist typically is counter current from the gas flow. Most commonly, the spray mist is directed downward from the top of the tower while the particulate matter-laden gas stream enters from the bottom and passes upward through a spray mist. The particulate matter entrained in the gas stream impacts the droplets and are then removed from the gas stream through a mist eliminator. Spray towers are not generally used for fine particulate matter applications because the equipment requires very high liquid to gas ratios. Collection efficiencies range from 70 to 99 percent depending on the application. (EPA-452/F-03-016). Scrubbers are an available control technology for EU IDs 105, 107, 109, 110, 114, and 128 through 130 which have captured emissions that can be controlled. EU ID 111 is not a controlled emission unit so use of a scrubber is not possible to capture $PM_{2.5}$ emissions. As a result, scrubbing is not an available control technology for EU ID 111.

Suppressant – Material Handling Emission Units $PM_{2.5}$ Control Option
The use of dust suppression to control particulate matter can be effective for stockpiles and transfer points exposed to the open air. Applying water or a chemical suppressant can bind the materials together into larger particles which reduces the ability to become entrained in the air either from wind or material handling activities. This technology works in practice on material handling sources that are exposed to wind and ambient conditions. Suppressants are an available particulate matter control for all the material handling emission units.

Enclosure – Material Handling Emission Units $PM_{2.5}$ Control Option

An enclosure prevents the release of fugitive emissions into the ambient air by confining all fugitive emissions within a structure and preventing additional fugitive emissions from being generated from winds eroding stockpiles and lifting particulate matter from conveyors. The RBLC identified enclosures as control technology for a number of emission units. Often the enclosures are paired with fabric filter control technology. The RBLC does not identify a control efficiency for an enclosure that is not associated with another control option. $PM_{2.5}$ emissions from each material handling source originate in an enclosure, so enclosures are available for particulate matter emission control.

Wind Screens – Material Handling Emission Units $PM_{2.5}$ Control Option

The RBLC identified several emission units with wind screens to control particulate matter emissions. A wind screen is much like a solid fence which is used to lower wind velocities near stockpiles and material handling sites. As wind speeds increase, so does fugitive particulate matter emissions from stockpiles, conveyors, and transfer points. The use of wind screens is appropriate for materials not already located in an enclosure. Because all the material handling emission units are enclosed, a wind screen is not an appropriate technology for controlling particulate matter emissions and is not an available technology.

Vents – Material Handling Emission Units $PM_{2.5}$ Control Option

Vents can control fugitive emissions by collecting fugitive emissions from enclosed loading, unloading, and transfer points and then venting emissions to the atmosphere or back into other equipment such as a storage silo. Vents that exhaust to atmosphere without a filter or other control device do not reduce emissions. Other vent control designs include closed systems and operating under a negative pressure. Closed system vent systems are available control options for EU IDs 105, 107, 109, 110, 114, and 128 through 130 because these emission units are located in enclosures with vents. EU ID 111 is enclosed during the ash transfer to the disposal trucks but the large vehicle doors must open for trucks to enter and exit the ash loadout facility. Installation of a vent would be ineffective because the ambient air exchange from the building while the doors are opened. Negative pressure vent systems are not an available technology for these material handling emission units beyond the pneumatic operation which is part of the design.

4.1.8 SUMMARY OF AVAILABLE $PM_{2.5}$ CONTROL OPTIONS

Table 4-1 summarizes the available $PM_{2.5}$ control options for the serious NAA $PM_{2.5}$ emission units at UAF. The large coal and biomass-fired boiler (EU ID 113) has five available $PM_{2.5}$ control technologies. Fabric filters are part of the proposed emission control design for this unit. Three add-on control technologies are ESP, scrubber and cyclone. The use of good combustion practice is also available.

The available $PM_{2.5}$ control technologies for the mid-sized diesel-fired boiler (EU ID 3) and the diesel and natural-gas fired boiler (EU ID 4) are the same. Because natural gas supply is limited in Fairbanks, the BACT analysis for EU ID 4 will focus on diesel operation. Although no add-on control technologies were identified in the RBLC for mid-sized diesel or natural gas-fired boilers, fabric filters, ESP, scrubber and cyclone controls are available along with limited operation and good combustion practices as shown in Table 4-1.

Scrubbing is the only add-on control technology identified as available for small boilers (EU IDs 19 through 21) to control $PM_{2.5}$. Table 4-1 shows limited operation and good combustion practices as the only other available control technologies for these small boilers.

Several control options are available for the large diesel-fired engine (EU ID 8), as shown in Table 4-1. EU ID 8 is using low ash diesel, is designed with positive crankcase ventilation, and has restricted operation. Diesel particulate matter filters can reduce emissions of $PM_{2.5}$ as well.

Table 4-1 identifies the small diesel-fired engine control options. EU ID 27 is operating under a federal emission standard as a Tier 3 engine and has restricted operating hours. A diesel particulate matter filter is the only add-on control technology available for the small engine.

As shown in Table 4-1, multiple chamber incinerator design is the only internal $PM_{2.5}$ control technology for the medical/pathological waste incinerator. The use of fabric filtration and ESP for $PM_{2.5}$ control as add-on controls, in addition to good combustion practices and limited operations, will be reviewed for the incinerator.

Nine material handling emission units with $PM_{2.5}$ control options are shown in Table 4-1. EU IDs 105, 107, 109, 110, 114, and 128 through 130 are enclosed emission units that have five available control options. EU ID 111, the ash loadout to truck transfer point, has two available control technologies identified because, unlike the other material handling points, the ash loadout building has large access doors for the disposal trucks which allows much of the building air to escape without the possibility for treatment.

4.2 Technical Feasibility of Available $PM_{2.5}$ Control Options

The following subsections describe the technical feasibility analyses for the available $PM_{2.5}$ control alternatives for the each of the emission units. A summary of the technically feasible control technologies for each type of emission unit is shown in Table 4-2.

4.2.1 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – $PM_{2.5}$ TECHNICAL FEASIBILITY

All five of the available control technologies are technically feasible for this boiler, although the level of particulate matter control varies widely. These five control technologies are fabric filtration, ESP, scrubber, cyclone, and good combustion practices.

4.2.2 MID-SIZED DIESEL-FIRED BOILERS (EU IDs 3 AND 4) – $PM_{2.5}$ TECHNICAL FEASIBILITY

Following the combustion of diesel fuel in the boilers, the exhaust gas contains fine particulate matter and unburned hydrocarbons. Indeck Keystone Energy, LLC was consulted about using $PM_{2.5}$ control equipment on these boilers because Indeck Keystone Energy, LLC acquired Zurn Energy Division, the original manufacturer of these emission units. Indeck Keystone Energy, LLC indicated that fabric filters, scrubbers and ESPs are not used on these types of diesel-fired boilers, as shown in Appendix B. The particulate matter created from diesel combustion is normally a substantial oily/tar/carbon mass, rather than a lighter dust or fly ash particle that is typical from coal or gas burning. The particulate matter from diesel combustion readily adheres to downstream control equipment. Filter bags would quickly become clogged by the unburned hydrocarbons preventing proper flow through the filter bags and creating high back pressure issues. The electromagnetically charged collection plates in the ESP could not release the particulate matter through mechanical rappers that use vibration to release the adhered material or through water washing. Material that would be released from the collection plates would adhere to the waste hopper and could not easily be removed for disposal. Scrubbers would have a similar problem because upon contact with the spray the droplet would become a larger but still sticky material that would adhere to the discharge piping requiring regular and extensive labor to clean and maintain. For these reasons, fabric filtration, EPS and scrubbing are not technically feasible $PM_{2.5}$ control options for these boilers and will not be reviewed any further in this BACT analysis.

Cyclone control of $PM_{2.5}$ has very limited efficiency, as described above. Cyclones are especially good as pre-cleaners and are ideal for flow streams that contain heavy particulate matter loading of large diameter particles and are at high temperature and in harsh environments. None of these qualities apply to the diesel-fired boilers exhaust gas. Typical cyclones are known to achieve from 0 to 40 percent $PM_{2.5}$ removal efficiencies, while high efficiency cyclones have been known to control 20 to 70 percent of the $PM_{2.5}$. The boiler exhaust does not have heavy particulate matter loading, the particulate matter size of interest is $PM_{2.5}$ for which cyclones have low collection efficiencies, and no RBLC entries identify the use of a cyclone for this type of application. The particulate matter created from the diesel combustion as described above would cause fouling of the cyclone, preventing proper cyclonic operation and requiring regular and extensive labor to clean and maintain the cyclone. Based on this information, cyclones are not technically feasible and will not be reviewed any further in this BACT analysis.

Limited operation is technically feasible for EU ID 4 because the unit currently operates with an annual heat input restriction and limited NO_X emissions. EU ID 3 does not currently have an operating limit. EU ID 3 is needed as backup to the current large boilers or the proposed new CFB boiler, should those boilers fail. On this basis, limited operation is technically feasible for EU ID 4, but is not technically feasible for EU ID 3.

Good combustion practices are technically feasible. Because good combustion practices are the only remaining $PM_{2.5}$ control option for EU ID 3, good combustion practices will be proposed as BACT for that boiler. No additional BACT review is necessary for EU ID 3.

Because EU ID 4 has limited operation and this control option reduces $PM_{2.5}$ emissions more than good combustion practices, UAF will propose that BACT for EU ID 4 be limited operation. No further BACT review is necessary for EU ID 4. Although eliminated from BACT consideration, good combustion practices are practiced for other reasons.

4.2.3 SMALL DIESEL-FIRED BOILERS (EU IDs 19 THROUGH 21) – $PM_{2.5}$ TECHNICAL FEASIBILITY

One add-on $PM_{2.5}$ emission control identified as available is a scrubber. Only one scrubber was identified among the eight RBLC entries. This scrubber was to be installed on unit rated at 90 MMBtu/hr. This unit is more than 14 times larger than the small boilers at UAF. Although Proctor Sales Inc, a scrubber vendor, has indicated that installing a scrubber for boilers the size of EU IDs 19 through 21 is technically feasible, scrubbers are not a typical application because of the high capital cost. Scrubbing is technically feasible for these small boilers and will be reviewed in this BACT analysis.

Another identified available control technology is limited hours of operation. These boilers already operate with limited hourly operating under Condition 10 of Air Quality Permit No. AQ0316MSS03. UAF cannot reduce the operations of these boilers to levels below this restriction without hindering the facility operations.

Because these boilers have operating limits that reduce $PM_{2.5}$ emissions, the use of good combustion practices will not be carried forward as an additional control option because good operating practices do not add any additional improvement to the current level of $PM_{2.5}$ control. Although eliminated from BACT consideration, good combustion practices are practiced for other reasons.

4.2.4 LARGE DIESEL-FIRED ENGINE (EU ID 8) – $PM_{2.5}$ TECHNICAL FEASIBILITY

Several concerns exist about the technical feasibility of using a DPF on EU ID 8. A Fairbanks Morse Engine employee stated that Fairbanks Morse have never supplied a DPF with a new engine or for aftermarket use. The RBLC has 86 PM control option entries for large diesel-fired engines, but none for a DPF. A commercially available DPF likely does not exist for large engines similar to EU ID 8. The Fairbanks Morse Engine employee emphasized that any post-combustion control technology sizing is critical such that the technology does not cause the total exhaust system backpressure to exceed the maximum allowable backpressure of the engine. An increase in the backpressure levels requires the engine to compress the exhaust gases to a higher pressure, which involve additional mechanical work and/or less energy extracted by the engine. Several of the effects of additional backpressure include:

- Increased pumping work,
- Reduced intake manifold boost pressure,
- Cylinder scavenging and combustion effects, and
- Turbocharger problems.

EU ID 8 has an SCR system that creates backpressure. Use of DPF is not technically feasible because DPF has not been demonstrated in practice based on the numerous RBLC entries. The backpressure issues are one of the possible reasons DPF is not commercially available.

Positive crankcase ventilation is technically feasible and already incorporated into the EU ID 8 design. EU ID 8 is combusting low ash diesel (distillate fuel oil) although the engine is designed to fire either heavy fuels or distillate fuel. As a result, the use of low ash fuels is technically feasible.

This engine has existing operating limits because of the shared NO_X emission limit that also effectively limits the potential emissions of all other air pollutants, including $PM_{2.5}$. UAF cannot reduce the operation of this engine to levels below these restrictions without hindering the ability to meet electricity needs. Limited operation will be carried forward as technically feasible at the current level of restriction. Because this large engine is operated using three technically feasible $PM_{2.5}$ control options, the use of good combustion practices will not be carried forward as an additional control option because this technology does not add any additional improvement to the current level of $PM_{2.5}$ emission control. Although eliminated from BACT consideration, good combustion practices are practiced for other reasons.

UAF will propose that $PM_{2.5}$ BACT for EU ID 8 be the use of the three existing control techniques currently in practice. These control techniques include positive crankcase ventilation, use of low ash fuel, and limited operation. No further BACT analysis will be completed for this engine.

4.2.5 SMALL DIESEL-FIRED ENGINE (EU ID 27) – $PM_{2.5}$ TECHNICAL FEASIBILITY

Four control technologies were identified as available for this small engine. A DPF is considered technically feasible for this small engine. This engine already is subject to an hourly operating limit and is subject to the Tier 3 federal emission standard. As a result, both limited operations and federal standards are considered technically feasible. UAF cannot reduce the hours of operations on this engine to lower levels without impacting facility electrical requirements. Because this small engine is operated using two technically feasible $PM_{2.5}$ control options, the use of good combustion practices will not be carried forward as an additional control option because this option would not reduce $PM_{2.5}$ emissions below the current control technologies. Although eliminated from BACT consideration, good combustion practices are practiced for other reasons, including compliance with federal emissions standards.

4.2.6 MEDICAL/PATHOLOGICAL WASTE INCINERATOR (EU ID 9A) – $PM_{2.5}$ TECHNICAL FEASIBILITY

Of the three identified control technologies for the incinerator, fabric filtration and the use of multiple chambers are considered technically feasible. The third control technology, ESP, is not technically feasible for this incinerator. The incinerator vendor, Therm Tec (see Appendix B), has indicated that the use of an ESP on this incinerator is not a viable $PM_{2.5}$ emission control option due to the 10 to 12 percent moisture content in and high temperature of the flue gas. The high moisture content and high temperature causes the particles to have a low resistivity. This phenomenon allows the particles to pick up the charge from the electrodes in the ESP quickly, but also allows the charged particle upon contacting the collection plate to rapidly lose charge, bounce off the collection plate, and become re-entrained in the flue gas. In general, Therm Tec states ESPs are expensive and inefficient for this type of application. Based on this information, an ESP will not be technically feasible for this application and will not be further reviewed in this BACT analysis.

This incinerator is operating with multiple chambers. This technology and the use of add on fabric filtration control technology are considered technically feasible and will be reviewed in this BACT analysis. The incinerator has an existing operating limit. Limited operations and good combustion practices are technically feasible.

4.2.7 MATERIAL HANDLING EMISSION UNITS (EU IDS 105, 107, 109 THROUGH 111, 114, AND 128 THROUGH 130) – $PM_{2.5}$ TECHNICAL FEASIBILITY

The material handling emission units have been divided into two groups because of physical differences. The larger group of emission units, EU IDs 105, 107, 109, 110, 114, and 128 through 130 will be equipped with poly-tetra-fluoro-ethylene (PTFE) membrane fabric filters. These fabric filters are technically feasible and are expected to control emissions such that $PM_{2.5}$ emissions will be 0.003 gr/dscf. These emission units are enclosed and fabric filters control the air vented from the enclosures. Table 4-2 shows enclosure and fabric filtration as a technically feasible control technology for EUs ID 105, 107, 109, 110, 114, and 128 through 130.

EU IDs 105, 107, 109, 110, 114, and 128 through 130 are enclosed emission units that are vented. The use of closed system venting is technically feasible for these emission units.

The use of water in a scrubber would be problematic in the Fairbanks climate. In the Interior Alaska environment, moisture from a scrubber would easily freeze in a scrubber or the mist eliminator, rendering the scrubber or mist eliminator inoperable. Moisture escaping with the exhausted gas stream would enhance the risk of forming ice fog. Using water to control coal, sand, or limestone handling would introduce moisture into the boiler which would change the combustion characteristics of these materials. Using a chemical suppressant on these materials could introduce new unwanted chemicals for atmospheric release. The use of water or water based suppressants poses too many risks to be considered a technically feasible control technology for particulate matter control for these material handling emission units. Scrubbers are not technically feasible $PM_{2.5}$ emission controls for any of the material handling emission units.

The use of water or a water-based suppressant also would be problematic in the Interior Alaska climate. Applications of water to materials exposed to the ambient winter conditions could create large frozen blocks of material. Adding water within the process would cause blockage in the fabric filters because the moisture would freeze or plug the filters, preventing air. The addition of moisture to emission units in enclosures that vent to the ambient air could also be a source of ice fog. EU IDs 105, 107, 109, 110, 114, and 128 through 130 are enclosed and are proposed to have fabric filter control technology in place. Suppressants are not an appropriate control technology because the result would be filters that freeze during the winter. Ice fog could potentially form and be problematic. As a result, suppressants are not technically feasible for these emission units.

The second group of material handling emission units consists of one emission unit, EU ID 111, which is the ash loadout. Application of a suppressant to the ash as the material is deposited into trucks would create ice during the winter months. The ice would prevent the haul truck from being able to dump the ash if frozen to the truck bed. The additional moisture in the warmer months of the year would cause for heavier truck loads that would increase fugitive road dust. For these reasons, use of a suppressant is not a technically feasible control technology for EU ID 111.

The ash unloading area is fully enclosed while ash is dropped from a hopper into the truck bed. Although the building around the ash loadout is closed during the loadout activity, the large truck doors are not closed at all times because the doors must be opened to allow the haul trucks to enter and leave the loadout station. The use of an enclosure for the ash loadout at EU ID 111 is considered technically feasible even though the loadout area is not a continuously maintained enclosure. Emissions for the ash loadout operation are based on the empirical equation from AP-42, section 13.2.4, which considers wind speed and ash moisture content. The mean Fairbanks wind speed was used with this empirical equation and no credit was taken for the enclosure surrounding this transfer point. As a result, the potential $PM_{2.5}$ emissions are likely overestimated. The use of the enclosure will be proposed as BACT for the EU ID 111 because enclosure is the only remaining control technology. No further analysis will be completed for EU ID 111.

4.2.8 SUMMARY OF $PM_{2.5}$ TECHNICAL FEASIBILITY

All five available control technologies identified for the large coal and biomass-fired boiler are considered technically feasible control technologies, as shown in Table 4-2.

Of the control technologies identified as available for mid-sized boilers, none of the add-on control technologies are technically feasible. Only good combustion practices remained feasible for EU ID 3, as shown in Table 4-2. EU ID 4 operates with limited operation, so this technology will be proposed as $PM_{2.5}$ BACT for EU ID 4. As a result, no further $PM_{2.5}$ BACT analysis will be completed for EU IDs 3 and 4.

Among the available control technologies identified for the small diesel-fired boilers, the scrubber and limited hours of operation are considered technically feasible.

The large diesel-fired engine has three technically feasible control options for consideration, as shown in Table 4-2. Positive crankcase ventilation is part of the engine design, the engine is using a low ash diesel fuel, and has limited operation. These three control options will be proposed as $PM_{2.5}$ BACT for EU ID 8.

Use of a DPF is the only new add-on control technology for $PM_{2.5}$ emission control from the small engine, EU ID 27, as shown in Table 4-2. EU ID 27 is operating in compliance with the applicable federal emission standard as a Tier 3 engine and is restricted to operating no more than 4,380 hours per year.

EU ID 9A has four technically feasible control options, the use of multiple chambers for combustion, good combustion practices, limited operation, and fabric filtration as an add-on control technology. EU ID 9A has an existing operating limit.

Table 4-2 shows the two groupings of material handling emission units. EU ID 111, as shown in the table, has enclosure as the only technically feasible control technology. This technology will be proposed as $PM_{2.5}$ BACT. EU IDs 105, 107, 109, 110, 114, and 128 through 130 have three available control technologies for further review.

4.3 Ranking of Technical Feasibility $PM_{2.5}$ Control Options

The following subsections rank the technically feasible control technologies for each equipment type by the ability to reduce $PM_{2.5}$ emissions. A summary of the rankings are found in Table 4-3.

4.3.1 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – $PM_{2.5}$ RANKING OF TECHNICAL FEASIBILITY

As shown in Table 4-3, each of the five technically feasible control technologies for EU 113 are ranked by $PM_{2.5}$ control efficiency. Fabric filters are estimated to provide the best $PM_{2.5}$ emission control. The EPA fact sheet for fabric filters indicates this technology can remove 99 to 99.9 percent of all sizes of particulate matter, including the small fraction of $PM_{2.5}$. The RBLC does not include any control efficiencies for fabric filter control technology determinations on

$PM_{2.5}$. For this analysis, the assumption is that a baghouse will capture 95 percent of the $PM_{2.5}$, a conservatively low assumption.

SCI indicated that an ESP has a lower particulate matter collection efficiency than a baghouse for this coal-fired boiler application. Based on this information, the average particulate matter collection efficiency of 90 percent was assumed based on the EPA ESP fact sheet. The scrubber and cyclone have even lower particulate matter collection efficiencies of 70 and 20 percent, respectively. The $PM_{2.5}$ emissions have been estimated based on the baghouse vendor emission rate guarantee and assuming a 95 percent level of control.

UAF is proposing to install a baghouse for particulate matter control on this boiler. The vendors for the baghouse designed for this boiler guarantee a $PM_{2.5}$ emission rate of 0.012 lb/MMBtu of heat input. The estimated level of control is approximately 95 percent of the $PM_{2.5}$. This baghouse is designed with filter bags that have the highest efficiency available for this application according to the vendor. Because the baghouse system has the highest level of $PM_{2.5}$ control of the five control technologies under consideration, UAF will propose that $PM_{2.5}$ BACT for EU ID 113 be a baghouse. Because UAF proposes to install a baghouse, no further review of impacts or other $PM_{2.5}$ control technologies is necessary.

4.3.2 SMALL DIESEL-FIRED BOILERS (EU IDs 19 THROUGH 21) – $PM_{2.5}$ RANKING OF TECHNICAL FEASIBILITY

EU IDs 19 through 21 share an operating limit of 19,650 hours per year to control NO_X. Although this analysis is focused on $PM_{2.5}$, the restricted operation must be considered as the base case jointly with any add-on control technology. The scrubber is the only technically feasible add-on $PM_{2.5}$ emission control technology for these small boilers. This technology can reduce the $PM_{2.5}$ emissions by 70 to 99 percent, which will reduce the overall emissions from all three boilers by less than 1 tpy, as shown in Table 4-3. For this analysis, the conservative assumption is that 99 percent of the $PM_{2.5}$ emission is controlled by the scrubber.

4.3.3 SMALL DIESEL-FIRED ENGINE (EU ID 27) – $PM_{2.5}$ RANKING OF TECHNICAL FEASIBILITY

EU ID 27 is a Tier 3 certified engine with an annual operating restriction. This existing configuration is the base-case for ranking the $PM_{2.5}$ emission control technologies. A DPF is the only additional particulate matter emission control considered for this engine. A DPF is estimated to remove less than 0.25 tpy of $PM_{2.5}$ emissions (an 85 percent control efficiency), as shown in Table 4-3.

4.3.4 MEDICAL/PATHOLOGICAL WASTE INCINERATOR (EU ID 9A) – $PM_{2.5}$ RANKING OF TECHNICAL FEASIBILITY

EU ID 9A is designed with a secondary combustion chamber in which organic particulate matter is destroyed. This existing configuration, along with the operating limit, is the base-case for ranking the $PM_{2.5}$ emission control technologies. Fabric filters are an add-on emission control technology that will be considered in addition to the use of multiple chambers. Fabric filters are estimated to capture 95 percent of $PM_{2.5}$ emissions.

4.3.5 MATERIAL HANDLING EMISSION UNITS WITH FABRIC FILTERS (EU IDS 105, 107, 109, 110, 114, AND 128 THROUGH 130) – $PM_{2.5}$ RANKING OF TECHNICAL FEASIBILITY

The current design incorporates the three technically feasible control technologies for EU IDs 105, 107, 109, 110, 114, and 128 through 130. Each material handling emission unit is enclosed. The vented emissions are treated by a fabric filter. EU IDs 105, 107, 109, 110, and 128 through 130 have exhaust flows of 1,000 acfm and are guaranteed to emit no more than 0.003 gr/dscf of $PM_{2.5}$. EU ID 114 is a much smaller emission unit with an exhaust flow of 5 acfm and a vendor guarantee to emit no more than 0.05 gr/dscf of $PM_{2.5}$. The proposed filters have the best level of control available, per vendor information. Although closed system venting is identified as a technically feasible control technology, re-designing the vent system and ducting the vents into the boiler combustion air intake or another closed system at the plant will result in $PM_{2.5}$ emission reductions of less than 0.23 tpy for any of these emission units. The annualized costs for re-design and ducting will not be quantified in this analysis due to the extremely low $PM_{2.5}$ emission reductions that could be achieved. The use of enclosure with fabric filter control technologies will be proposed as BACT for these material handling emission units. No further BACT review is necessary.

4.4 Additional Impacts of Technically Feasible $PM_{2.5}$ Control Options

The following subsections describe the energy, environmental, and economic impacts associated with the alternative control options for the various equipment. The control technologies offering the greatest level of $PM_{2.5}$ removal will be reviewed for impact. If the control technology offering the greatest level of $PM_{2.5}$ emission control is not appropriate as BACT, then the next control technology offering the second greatest level of $PM_{2.5}$ emission removal is reviewed. If the second greatest level of $PM_{2.5}$ control is not BACT, then the review continues until a technically feasible emission control technology is identified.

Cost estimates were prepared for the various control technologies by SCI with input from control technology vendors. The supporting cost estimates from SCI can be found in Tables 4-4 through 4-9.

4.4.1 SMALL DIESEL-FIRED BOILERS (EU IDs 19 THROUGH 21) – SCRUBBER

Energy Impacts

The small diesel-fired boilers will be subject to an increased need for energy to operate a scrubber. This cost has not been estimated at this time.

Environmental Impacts

The scrubber will produce a liquid waste stream that will need to be treated and disposed appropriately. The associated impact from this waste stream has not been assessed at this time.

Economic Impacts

The total capital cost to install one scrubber on the exhaust from three boilers has been estimated by Proctor Sales Inc. to be $300,000. This cost is shown in Table 4-4. This cost estimate from Proctor Sales is provided in Appendix B. This scrubber is conservatively assumed to control 99 percent of the $PM_{2.5}$ emission. Because of the large capital cost, no additional costs have been estimated at this time.

The annualized cost for a scrubber on these small diesel boilers of $42,713 is based on the capital recovery cost and does not include any annual operating or maintenance costs, as shown in Table 4-5. This scrubber would control less than one ton per year of $PM_{2.5}$ emissions. The cost-effectiveness of using a scrubber to control $PM_{2.5}$ on these boilers is $47,939 per ton of $PM_{2.5}$ removed. The cost-effectiveness of using a scrubber to control these emissions is much higher than a reasonable cost for emission control technology.

BACT will be proposed as the use of the shared limited annual hours of operation.

4.4.2 SMALL DIESEL-FIRED ENGINE (EU ID 27) – DIESEL PARTICULATE FILTER

Energy Impacts

The small diesel-fired engine will not be subject to any significant additional requirement of energy with the installation of a DPF.

Environmental Impacts

The existing silencer on EU ID 27 will need to be removed to allow for the installation of a DPF. A minimal change in noise without the silencer is expected to occur because the DPF will have an insulating blanket that will control both noise and heat. No other environmental impacts are anticipated.

Economic Impacts

The total capital cost to install a DPF is $30,751 as estimated by SCI in Table 4-6. NC Power Systems has estimated the cost of a standalone DPF that will require the removal of the existing silencer during installation of the DPF (see Appendix B). The new DPF will need to have an insulating blanket that is used for noise and heat control. The silencer will be removed during the two days effort as part of the DPF installation.

No annual maintenance costs have been included in the annualized costs at this time. Table 4-7 shows the expected annualized cost as $4,378. The DPF is expected to remove up to 85 percent of the $PM_{2.5}$ from the engine exhaust. Because only 0.26 tons per year of $PM_{2.5}$ are expected to be emitted from this small diesel engine before the use of a DPF, only 0.22 tons of $PM_{2.5}$ will be controlled. As a result, the cost effectiveness of a DPF is $19,811 per ton of $PM_{2.5}$ removed. This cost is not reasonable for an emission control technology. On this basis, a DPF is not economical as BACT.

BACT will be proposed to be the 40 CFR 60 Subpart IIII particulate matter standard and the use of limited annual operating hours. EU ID 27 is a certified Tier 3 engine which meets the requirements of 40 CFR 60 Subpart IIII. EU ID 27 also is restricted to 4,380 operating hours per year per Condition 4 of Air Quality Permit No. AQ0316MSS03.

4.4.3 MEDICAL/PATHOLOGICAL WASTE INCINERATOR (EU ID 9A) – FABRIC FILTER + MULTIPLE CHAMBERS

Energy Impacts

The medical/pathological waste incinerator is operating with a secondary combustion chamber. No additional energy impacts are associated with the multiple staged combustion control technology because the incinerator will operate in this manner regardless of the fabric filter determination. The addition of a fabric filter system on the incinerator exhaust has no identified energy impacts.

Environmental Impacts

No identified negative environmental impacts are associated with the use of a fabric filter on the incinerator.

Economic Impacts

The total capital costs estimated to install a fabric filter would be $1,300,000 according to Therm Tec (see Appendix B). The capital cost includes a complete fabric filter system consisting of 70 bags which must be insulated and preheated. The flue gas temperature must be reduced from

1,700 degrees F to approximately 450 degrees F prior to entering the fabric filter system. To accomplish this reduction, the flue gas must be directed to a fire tube boiler, then to a cooling tower before entering the baghouse. The existing exhaust stack must be capped so that all flue gas is redirected into the boiler. The new stack must be refractory lined. These expenses are included in the cost of the fabric filter system.

The fabric filter system would operate under negative pressure. The exhaust system, including the fan, must be designed to operate in the harsh environment of the incinerator exhaust gas.

Expected maintenance includes the replacement of all 70 bags on a 12 month to 18 month cycle at a cost of $300 per bag plus labor costs. The annualized cost for the fabric filter is estimated to be $217,011. Because the controlled $PM_{2.5}$ emissions are less than 0.5 tpy, the cost effectiveness of installing a fabric filter on the incinerator is $761,441 per ton of $PM_{2.5}$ removed. This cost is much greater than a reasonable cost for emission control technology. The estimated capital and annual costs are provided in Tables 4-8 and 4-9.

Because the cost effectiveness of fabric filter is very high, this $PM_{2.5}$ control technology is not economical as $PM_{2.5}$ BACT. The use of multiple combustion chambers and the existing operating limit will be proposed as $PM_{2.5}$ BACT.

4.4.4 SUMMARY OF BACT ANALYSIS FOR $PM_{2.5}$

Based on the above analysis, Table 4-10 summarizes the $PM_{2.5}$ BACT economics for each type of equipment. No annual operating or maintenance costs are estimated for the scrubber reviewed for EU IDs 19 through 21 or for the DPF for EU ID 27. These two control technologies were found to have very high cost effectiveness values without the inclusion of annual operating and maintenance costs. The analysis for EU ID 9A did include annual operating and maintenance costs for the fabric filter analysis. This cost effectiveness was extremely high. All three cost effectiveness values are very high because the amount of $PM_{2.5}$ emitted from these emission units is less than 1 tpy, each. The existing base-case control technologies are proposed as $PM_{2.5}$ BACT for each of these emission units. These controls include: limited operation of 19,650 hr/yr, combined, for EU IDs 19 through 21; limited operation of 4,380 hr/yr for EU ID 27 and compliance with the Tier 3 engine limits; and, limited operation of 109 tpy waste and using a multiple chamber incinerator design for EU ID 9A.

A complete summary of the proposed $PM_{2.5}$ BACT control technologies and emission rates are provided in Table 4-11. Although good combustion practices are not always identified as the proposed BACT determination, UAF follows these practices for their equipment. The proposed $PM_{2.5}$ BACT for the large CFB boiler (EU ID 113) is the use of a baghouse because this fabric filter technology offers the best particulate matter emission control for the coal-fired boiler.

No technically feasible add-on $PM_{2.5}$ emission control options were identified for EU IDs 3 and 4. Good combustion practices are proposed as $PM_{2.5}$ BACT for EU ID 3. The existing operating limit is proposed as $PM_{2.5}$ BACT for EU ID 4.

EU IDs 19 through 21 are small diesel-fired boilers that share an operating limit of 19,650 hr/yr. This existing operating limit is proposed as $PM_{2.5}$ BACT for these small boilers.

The proposed $PM_{2.5}$ BACT for the large diesel-fired engine, EU ID 8, is three existing emission controls. These controls include the positive crankcase ventilation design of the engine, use of low ash fuel which is standard diesel fuel, and an emission limit. EU ID 8 shares an annual NOx emission limit with EU ID 4. This limit translates into a restriction on fuel consumption for EU ID 8, which limits annual $PM_{2.5}$ emissions. These three emission controls are proposed as $PM_{2.5}$ BACT for EU ID 8.

The proposed $PM_{2.5}$ BACT for the small diesel-fired engine, EU ID 27, is the existing 40 CFR 60 Subpart IIII emission limit and limited annual operation. EU ID 27 is a small engine that must meet the emission limits from 40 CFR 60 Subpart IIII as a Tier 3 engine. The engine has a permitted operating restriction of 4,380 hours per year.

The control technology proposed as $PM_{2.5}$ BACT for the medical/pathological waste incinerator, EU ID 9A, is the use of the multiple chamber combustion design of the incinerator and the existing operating limit. The $PM_{2.5}$ emission rate of 0.25 tpy makes the addition of any other $PM_{2.5}$ emission control too costly.

The $PM_{2.5}$ BACT analysis for the material handling emission units was conducted as two groups. The emission units that will be enclosed and equipped with fabric filtration include: EU IDs 105, 107, 109, 110, 114, and 128 through 130. $PM_{2.5}$ BACT is proposed to be the use of fabric filtration for these emission units.

EU ID 111, the ash loadout operation, is the only material handling emission unit that is not fully enclosed at all times. Capturing $PM_{2.5}$ emissions in a fabric filter system is not possible because the air in the ash loadout building is exchanged with ambient air whenever the doors are opened for haul trucks access to the building. The use of this part-time enclosure is proposed as $PM_{2.5}$ BACT because part-time enclosure is the only technically feasible control for this material handling operation.

Table 4-1. UAF - Available $PM_{2.5}$ Control Options

Emission Unit		Available Control Options
ID	Description	
113	Large Coal and Biomass-fired Boiler	Fabric Filters
		ESP
		Scrubber
		Cyclone
		Good Combustion Practices
3 and 4	Mid-sized Diesel-fired Boilers	Fabric Filters
		ESP
		Scrubber
		Cyclone
		Limited Operation
		Good Combustion Practices
19 through 21	Small Diesel-fired Boilers	Scrubber
		Limited Operation
		Good Combustion Practices
8	Large Diesel-fired Engine	DPF
		Positive Crankcase Ventilation
		Low Ash Diesel
		Limited Operation
		Good Combustion Practices
27	Small Diesel-fired Engines	DPF
		Federal Standard
		Limited Operation
		Good Combustion Practices
9A	Medical/Pathological Waste Incinerator	Fabric Filters
		ESP
		Limited Operation
		Good Combustion Practices
		Multiple Chambers
105, 107, 109, 110, 114, and 128 through 130	Material Handling Sources with Fabric Filtration	Fabric Filters
		Scrubber
		Suppressant
		Enclosure
		Closed System Vent
111	Material Handling Sources without Fabric Filtration	Suppressant
		Enclosure

Table 4-2. UAF - Technically Feasible $PM_{2.5}$ Control Options

Emission Unit ID	Emission Unit Description	Technically Feasible Control Options
113	Large Coal and Biomass-fired Boiler	Fabric Filters
		ESP
		Scrubber
		Cyclone
		Good Combustion Practices
3	Mid-sized Diesel Fired Boiler	Good Combustion Practices
4	Mid-sized Diesel Fired Boiler	Limited Operation
19 through 21	Small Diesel-fired Boilers	Scrubber
		Limited Operation
8	Large Diesel-fired Engine	Positive Crankcase Ventilation
		Low Ash Diesel
		Limited Operation
27	Small Diesel-fired Engine	DPF
		Federal Standard
		Limited Operation
9A	Medical/Pathological Waste Incinerator	Fabric Filters
		Limited Operation
		Good Combustion Practices
		Multiple Chambers
105, 107, 109, 110, 114, and 128 through 130	Material Handling Emission Units with Fabric Filtration	Fabric Filters
		Enclosure
		Closed System Venting
111	Material Handling Emission Unit without Fabric Filtration	Enclosure

Table 4-3. UAF - Ranking of Technically Feasible $PM_{2.5}$ Control Options

Emission Unit ID	Emission Unit Description	Control Technology	Control Efficiency (pct.)	$PM_{2.5}$ Emissions (tpy)	Emissions Reduction (tpy)
113	Large Coal and Biomass-fired Boiler	Fabric filter	95	15.5	294.5
		ESP	90	31	279
		Scrubber	70	93	217
		Cyclone	20	248	62
		Good Combustion Practices	0	310	0
19 through 21	Small Diesel-fired Boilers[1]	Scrubber + Limited Operation	99	0.01	0.93
		Limited Operation	0	0.94	0.0
27	Small Diesel-fired Engine	DPF + (Federal Limit + Limited Operation)	85	0.04	0.22
		Federal Limit + Limited Operation	0	0.26	0
9A	Medical/Pathological Waste Incinerator	Fabric Filters + Multiple Chambers	95	0.01	0.24
		Multiple Chambers + (Limited Operation)	0	0.25	0
105, 107, 109, 110, 114, and 128 through 130	Material Handling Emission Units with Fabric Filtration	Closed System Venting	100	0	Varies[2]
		Fabric Filter + Enclosure	0	Varies[2]	0

Table 4-4. UAF - Capital Costs for Scrubber on the Small Diesel-Fired Boilers (EU IDs 19 through 21)

Shaded cells indicate user inputs.

Total Capital Investment Determination - Scrubber

Project: UAF $PM_{2.5}$ BACT Analysis - BiRD Boilers 1 through 3 (EU19 through 21; WM 2094W)

Date: 12/18/2015
Prepared By: C. Stevenson
Checked By: J. Rubino
Rev: B

Capital Costs

DIRECT COSTS	QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1) Purchased equipment and material costs							
(a) Basic equipment							
Scrubber for 3 Boilers, Units 19, 20, & 21 (includes freight & install)	1	EA	300000	$ 300,000			
(per Proctor Sales Inc.)						**TOTAL =**	**$ 300,000**
(b) Instrumentation							
Total Instrumentation		EA		$ -	Included in above price		
						TOTAL =	**$ -**
(c) Freight							
		% MATL COST			$ -		
						TOTAL =	**$ -**
(d) Labor							
Labor - offsite fab	0	MH		None required	$ -		
Labor - onsite	0	MH	$ -		$ -		
						TOTAL =	**$ -**
(e) Vendor representatives fees							
Fab Site Vendor Representatives fees (enter no. of days and daily rate)	0	Days			$ -		
Onsite Vendor Representatives fees (enter no. of days and daily rate)	0	Days			$ -		
						TOTAL =	**$ -**
Purchased Equipment and Material Cost (PEMC)						**PEMC =**	**$ 300,000**
Direct Installation Costs (DIC)						**DIC =**	
Total Direct Costs (TDC)						**TDC = (PEMC) + (DIC) =**	**$ 300,000**
INDIRECT COSTS							
(2) Engineering, Procurement & Construction Support Services		% TDC			$ -		Excluded in this estimate.
(3) Performance tests		EA			$ -		Excluded in this estimate.
Total Indirect Costs (TIC)						**TIC =**	**$ -**
MANAGEMENT AND CONTINGENCY COSTS							
(4) Unit Operator Costs		% TDC					Excluded in this estimate.
(5) Contingency		% TDC			$ -		Excluded in this estimate.
Total Management and Contingency Costs (TM&CC)						**TM & CC =**	**$ -**
TOTAL CAPITAL INVESTMENT (TCI)						**TCI = (TDC)+(TIC)+(TM&CC) =**	**$ 300,000**

Table 4-5. UAF - Annualized Costs for Scrubber on the Small Diesel-Fired Boilers (EU IDs 19 through 21)

Shaded cells indicate user inputs

Cost Effectiveness Determination - Scrubber						Date:	12/18/2015
Project:	UAF $PM_{2.5}$ BACT Analysis - BiRD Boilers 1 through 3 (EU19 through 21; WM 2094W)					Prepared By:	C. Stevenson
						Checked By:	J. Rubino
						Rev:	B
Annualized Costs							
DIRECT ANNUAL COSTS - EXCLUDED IN THIS ESTIMATE	**QTY**	**UNIT**	**UNIT COST**	**TOTAL MATERIALS COST**	**TOTAL LABOR COST**		**TOTAL**
(1) Operating Labor		MH			$ -		$ -
(2) Supervisory Labor		MH			$ -		$ -
(3) Maintenance Labor		MH			$ -		$ -
(4) Maintenance Materials		LOT		$ -			$ -
Total Direct Annual Costs (TDAC)	Excluded in this estimate					TDAC =	$ -
INDIRECT ANNUAL COSTS							
(5) Overhead		MH		Excluded in this estimate.	$ -		$ -
(6) Administrative Charges		MH		Excluded in this estimate.	$ -		$ -
(7) Property tax				Not Applicable			
(8) Insurance				Excluded in this estimate.			
Capital Recovery Factor [see inputs below]	0.1424						
(9) Capital Recovery						**CRF * TCI =**	$ 42,713
Total Indirect Annual Costs (TIAC)						TIAC =	$ 42,713
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 42,713
Cost Effectiveness Summary							
TOTAL TONS AVOIDED PER YEAR						=	0.891
COST EFFECTIVENESS ($ PER TON AVOIDED)						(TAC)/(TPY) =	$ 47,939

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years
Catalyst Life	N/A	years
Asset Utilization	N/A	%

Table 4-6. UAF - Capital Costs for DPF on the Small Diesel-Fired Engine (EU ID 27)

Shaded cells indicate user inputs.

Total Capital Investment Determination - DPF

Project: UAF $PM_{2.5}$ BACT Analysis - ACEP Engine (EU 27)

Date: 12/18/2015
Prepared By: C. Stevenson
Checked By: J. Rubino
Rev: C

Capital Costs

DIRECT COSTS	QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1) Purchased equipment and material costs							
(a) Basic equipment							
Total DPF System	1	EA	26428	$ 26,428			
(per NC Power Systems)						TOTAL = $	26,428
(b) Instrumentation							
Total Instrumentation		EA		$ -	Included in above price		
						TOTAL = $	-
(c) Freight							
DPF Freight		% MATL COST	10%		$ 2,643		
						TOTAL = $	2,643
(d) Labor							
Labor - offsite fab	0	MH		None required	$ -		
Labor - onsite	16	MH	$ 105.00		$ 1,680		
(per SCI)						TOTAL = $	1,680
(e) Vendor representatives fees							
Fab Site Vendor Representatives fees (enter no. of days and daily rate)	0	Days			$ -		
Onsite Vendor Representatives fees (enter no. of days and daily rate)	0	Days			$ -		
						TOTAL = $	-
Purchased Equipment and Material Cost (PEMC)						PEMC = $	30,751
Direct Installation Costs (DIC)	**DPF replaces existing silencer, no direct installation costs necessary**					DIC = $	-
Total Direct Costs (TDC)						TDC = (PEMC) + (DIC) = $	30,751
INDIRECT COSTS							
(2) Engineering, Procurement & Construction Support Services		% TDC			$ -		Excluded in this estimate.
(3) Performance tests		EA			$ -		Excluded in this estimate.
Total Indirect Costs (TIC)						TIC = $	-
MANAGEMENT AND CONTINGENCY COSTS							
(4) Unit Operator Costs		% TDC					Excluded in this estimate.
(5) Contingency		% TDC			$ -		Excluded in this estimate.
Total Management and Contingency Costs (TM&CC)						TM & CC = $	-
TOTAL CAPITAL INVESTMENT (TCI)						TCI = (TDC)+(TIC)+(TM&CC) = $	30,751

Table 4-7. UAF - Annualized Costs for DPF on the Small Diesel-Fired Engine (EU ID 27)

Shaded cells indicate user inputs

Cost Effectiveness Determination - DPF							Date:	12/18/2015
Project:	UAF $PM_{2.5}$ BACT Analysis - ACEP Engine (EU 27)						Prepared By:	C. Stevenson
							Checked By:	J. Rubino
							Rev:	C
Annualized Costs								
DIRECT ANNUAL COSTS		**QTY**	**UNIT**	**UNIT COST**	**TOTAL MATERIALS COST**	**TOTAL LABOR COST**		**TOTAL**
(1)	Operating Labor		MH			$ -		$ -
(2)	Supervisory Labor		MH			$ -		$ -
(3)	Maintenance Labor		MH			$ -		$ -
(4)	Maintenance Materials		LOT		$ -			$ -
Total Direct Annual Costs (TDAC)		Excluded in this estimate					TDAC =	$ -
INDIRECT ANNUAL COSTS								
(5)	Overhead		MH		Excluded in this estimate.	$ -		$ -
(6)	Administrative Charges		MH		Excluded in this estimate.	$ -		$ -
(7)	Property tax				Not Applicable			
(8)	Insurance				Excluded in this estimate.			
	Capital Recovery Factor [see inputs below]	0.1424						
(9)	Capital Recovery						**CRF * TCI =**	$ 4,378
Total Indirect Annual Costs (TIAC)							TIAC =	$ 4,378
TOTAL ANNUALIZED COSTS (TAC)							TAC = (TDAC) + (TIAC) =	$ 4,378
Cost Effectiveness Summary								
TOTAL TONS AVOIDED PER YEAR							=	0.22
COST EFFECTIVENESS ($ PER TON AVOIDED)							(TAC)/(TPY) =	$ 19,811

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years
Catalyst Life	N/A	years
Asset Utilization	N/A	%

Table 4-8. UAF - Capital Costs for a Fabric Filter on the Medical/Pathological Waste Incinerator (EU ID 9A)

Shaded cells indicate user inputs.

Total Capital Investment Determination - Fabric Filter					Date:	12/18/2015
Project: UAF $PM_{2.5}$ BACT Analysis - BiRD INCINERATOR (EU 9A)					Prepared By:	C. Stevenson
					Checked By:	J. Rubino
					Rev:	B

Capital Costs

DIRECT COSTS	QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1) Purchased equipment and material costs							
(a) Basic equipment							
FABRIC FILTRATION - INSTALLED (per Thermtec)	1	EA	1300000	$ 1,300,000		TOTAL =	$ 1,300,000
(b) Instrumentation							
Total Instrumentation		EA		$ -	Included in above price	TOTAL =	$ -
(c) Freight							
Freight included in basic equipment cost		% MATL COST			$ -	TOTAL =	$ -
(d) Labor							
Labor - offsite fab	0	MH			$ -		
Labor - onsite	0	MH	$ -		$ -	TOTAL =	$ -
(e) Vendor representatives fees							
Fab Site Vendor Representatives fees (enter no. of days and daily rate)	0	Days			$ -		
Onsite Vendor Representatives fees (enter no. of days and daily rate)	0	Days			$ -	TOTAL =	$ -
Purchased Equipment and Material Cost (PEMC)						PEMC =	$ 1,300,000
Direct Installation Costs (DIC)						DIC =	
Total Direct Costs (TDC)						TDC = (PEMC) + (DIC) =	$ 1,300,000
INDIRECT COSTS							
(2) Engineering, Procurement & Construction Support Services		% TDC			$ -		Excluded in this estimate.
(3) Performance tests		EA			$ -		Excluded in this estimate.
Total Indirect Costs (TIC)						TIC =	$ -
MANAGEMENT AND CONTINGENCY COSTS							
(4) Unit Operator Costs		% TDC					Excluded in this estimate.
(5) Contingency		% TDC			$ -		Excluded in this estimate.
Total Management and Contingency Costs (TM&CC)						TM & CC =	$ -
TOTAL CAPITAL INVESTMENT (TCI)						TCI = (TDC)+(TIC)+(TM&CC) =	$ 1,300,000

Table 4-9. UAF - Annualized Costs for a Fabric Filter on the Medical/Pathological Waste Incinerator (EU ID 9A)

Shaded cells indicate user inputs

Cost Effectiveness Determination - Fabric Filter					Date:	12/18/2015
Project: UAF $PM_{2.5}$ BACT Analysis - BiRD INCINERATOR (EU 9A)					Prepared By:	C. Stevenson
					Checked By:	J. Rubino
					Rev:	B
Annualized Costs						
DIRECT ANNUAL COSTS	**QTY**	**UNIT**	**UNIT COST**	**TOTAL MATERIALS COST**	**TOTAL LABOR COST**	**TOTAL**
(1) Operating Labor		MH			$ -	$ -
(2) Supervisory Labor		MH			$ -	$ -
(3) Maintenance Labor (clean boiler/heat exchanger)	104	MH	105		$ 10,920	$ 10,920
(4) Maintenance Materials (Bag replacement) (per Thermtec)	70	LOT	300	$ 21,000		$ 21,000
Total Direct Annual Costs (TDAC)	Excluded in this estimate				**TDAC =**	$ 31,920
INDIRECT ANNUAL COSTS						
(5) Overhead		MH		Excluded in this estimate.	$ -	$ -
(6) Administrative Charges		MH		Excluded in this estimate.	$ -	$ -
(7) Property tax				Not Applicable		
(8) Insurance				Excluded in this estimate.		
Capital Recovery Factor [see inputs below]	0.1424					
(9) Capital Recovery					**CRF * TCI =**	$ 185,091
Total Indirect Annual Costs (TIAC)					**TIAC =**	$ 185,091
TOTAL ANNUALIZED COSTS (TAC)					**TAC = (TDAC) + (TIAC) =**	$ 217,011
Cost Effectiveness Summary						
TOTAL TONS AVOIDED PER YEAR					=	0.285
COST EFFECTIVENESS ($ PER TON AVOIDED)					**(TAC)/(TPY) =**	$ 761,441

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manua	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years
Catalyst Life	N/A	years
Asset Utilization	N/A	%

Table 4-10. UAF - $PM_{2.5}$ BACT Cost Effectiveness
Summary for Each Emission Unit Type

Control Technology Option	Total Installed Capital ($)	Annualized Capital Cost ($/year)	Annual O&M Cost ($MM/year)	Cost Effectiveness ($/ton $PM_{2.5}$ removed)
Small Diesel-fired Boilers (EU ID 19 through 21)				
Scrubber + Limited Operation	$300,000	$42,713	NA	$47,939
Limited Operation[1]	~	~	~	~
Small Diesel-fired Engine (EU ID 27)				
DPF + Federal Limits + Limited Operation	$30,751	$4,378	NA	$19,811
Federal Limits[1] + Limited Operation[1]	~	~	~	~
Medical/Pathological Waste Incinerator (EU ID 9A)				
Fabric Filters + Multiple Chambers	$1,300,000	$217,011	$31,920	$761,441
Multiple Chambers + Limited Operation[1]	~	~	~	~

Notes:
[1] This technology is proposed as the baseline case.

Table 4-11. UAF - Proposed $PM_{2.5}$ BACT and Associated Emission Rate for Each Emission Unit Type

Emission Unit		Fuel	$PM_{2.5}$ BACT	
ID	Description		Description	Emission Rate[1]
113	Large Boiler	Coal and Biomass	Fabric Filter	0.012 lb/MMBtu
3	Mid-sized Boiler	Diesel	Good Combustion Practices	0.016 lb/MMBtu
4	Mid-sized Boiler	Diesel	Limited Operation	0.016 lb/MMBtu
		Natural Gas		7.6 lb/MMscf
19 through 21	Small Boilers	ULSD	Limited Operation	7.06 g/MMBtu
8	Large Engine	Diesel	Positive Crankcase Ventilation + Low Ash Fuel + Limited Operation	0.32 g/hp-hr
27	Small Engine	ULSD	Federal Limit (NSPS Subpart IIII, Tier 3) + Limited Operation	0.11 g/hp-hr
9A	Medical/Pathological Waste Incinerator	Waste	Multiple Chambers + Limited Operation	4.67 lb/ton
105, 107, 109, 110, and 128 through 130	Material Handling Emission Units with Fabric Filtration	N/A	Fabric Filter + Enclosure	0.003 gr/dscf
114	Material Handling Emission Units with Fabric Filtration	N/A	Fabric Filter + Enclosure	0.05 gr/dscf
111	Material Handling Emission Unit without Fabric Filtration	N/A	Enclosure	5.5e-5 lb/ton

5.0 SO_2 BACT Analysis

SO_2 is formed as a by-product of combustion from the sulfur in the fuel. SO_2 contributes indirectly to the formation of $PM_{2.5}$ through atmospheric chemical reactions that produce sulfate aerosol particles. This BACT analysis includes a review of control options that will reduce the SO_2 emissions either by reducing the formation of SO_2 during combustion or by removing SO_2 from exhaust gases. As shown in Table 1-2, the emission units that require an SO_2 BACT analysis are:

- EU ID 113, a large CFB coal and biomass-fired boiler;
- EU IDs 3 and 4, mid-sized diesel-fired and dual-fired (diesel and natural gas-fired) boilers, respectively;
- EU IDs 19, 20, and 21, small diesel-fired boilers;
- EU ID 8, a large diesel-fired engine;
- EU ID 27, a small diesel-fired engine; and
- EU ID 9A, a medical/pathological waste incinerator.

EU IDs 103 through 105, 107, 109 through 111, 114, and 128 through 130 are all material handling emission units which do not have any SO_2 emissions and so do not require an SO_2 BACT analysis.

5.1 Available SO_2 Control Options

The following subsections provide technical summaries and availability analyses for the SO_2 control technology options identified for each of the emission units. Similar to the NO_X and $PM_{2.5}$ pollutants, a review of the RBLC from 2005 to August 24, 2015, for all control technology determinations on applicable emission units was conducted. The RBLC identified multiple SO_2 BACT determinations.

5.1.1 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – SO_2 CONTROL OPTIONS

This boiler has a CFB combustion chamber which uses limestone injection to control SO_2 emissions. Similar to the NO_X and $PM_{2.5}$ analyses, the RBLC for large coal and biomass-fired boilers rated at greater than 250 MMBtu/hr was reviewed for SO_2 control technologies. The RBLC identified the following control technologies:

- Flue Gas Desulfurization (FGD)/Scrubber/Spray Dryer;
- Limestone Injection;
- Low Sulfur Coal; and
- Good Combustion Practices.

FGD/Scrubber/Spray Dryer – Large CFB Boiler SO_2 Control Option
Two basic types of FGD systems exist, dry and wet scrubbing. 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. Generally, particulate matter has not been removed prior to entering the adsorber, and the spray drying process acts as a combined SO_2/particulate matter removal system. 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 particulate matter collection device, such as a baghouse.

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. A particulate matter collection device is also required for dry scrubbing.

FGD systems are typically used if uncontrolled SO_2 emissions are high and/or eliminating the sulfur from the fuel supply is uneconomical or impossible. FGD scrubbing systems are capable of removal efficiencies in the range of 50 to 98 percent. The highest removal efficiencies are achieved by wet scrubbers at greater than 90 percent. The lowest removal efficiencies are achieved by dry scrubbers with typically less than 80 percent reduction (EPA-452/F-03-034). FGD is most commonly added to a coal fired boiler with limestone injection only if the fuel is a very high sulfur fuel such as a waste coal or refinery petroleum coke. Otherwise, the additional SO_2 reduction is minimal.

The vendor of this proposed boiler, Babcock & Wilcox, indicated that this new boiler design can accommodate a wet or dry FGD system. The recommended semi-dry FGD system is a spray dry absorber (SDA) that would be located at grade between the air heater and the baghouse. The current baghouse and filter media is capable of handling the higher solids loading from an SDA. The system would utilize a baghouse fly ash recycle system which would activate a portion of the un-reacted lime in the fly ash. The recycled slurry, when sprayed through the atomizer, will reduce the SO_2 emissions, possibly without the need for any additional reagent depending on the level of SO_2 reduction required. The proposed SDA technology is expected to achieve an SO_2 emission rate of 0.04 lb SO_2/MMBtu, which is approximately 92 percent control.

Babcock & Wilcox indicated that the boiler design should include a small dry sorbent injection (DSI) system to reduce hydrofluoric acid (HF) and hydrochloric acid (HCl) emissions if needed. This small DSI system is not designed for SO_2 emission control. An add-on DSI system for control of SO_2 emissions is considered as an available control technology for this boiler.

An add-on DSI system is possible and would use sodium bicarbonate or specialized hydrated lime as a reagent to react with SO_2. This form of a dry FGD system would likely require a silo for reagent storage, a mill building, pneumatic conveying, and reagent distribution upstream of the baghouse. Potentially, the baghouse ash handling system capacity would also need to be increased, depending on the sorbent injection rate. The add-on DSI system could achieve approximately a 75 percent SO_2 emission reduction. Sodium can react with NO_X to create a brown plume. The use of hydrated lime would prevent the creation of a brown plume.

Both SDA and DSI will be evaluated as separate control technologies available for the large coal-fired boiler.

Limestone Injection – Large CFB Boiler SO_2 Control Option
In the limestone injection process, crushed coal and limestone are suspended in a boiler by an upward stream of hot air. The coal is burned in this bubbling fluidized mixture. The temperature in the combustion chamber of between 1,500 and 1,600 degrees F is the correct temperature for the limestone to react with SO_2 to form a solid compound that is collected in a particulate matter collection device. The sulfur reduction can be achieved with either dry limestone or hydrated lime. Limestone injection technology has the benefits of low capital costs, low feed rates, and low operating costs.

The CFB design of the proposed boiler is capable of using limestone as part of the feed bed which controls the sulfur emissions released during coal combustion. The proposed fabric filter baghouse system would remove the particulate matter formed as calcium sulfate. Limestone injection is an available control technology.

Low Sulfur Coal – Large CFB Boiler SO_2 Control Option
UAF purchases coal from the Usibelli Coal Mine located in Healy, Alaska. This coal mine is 115 miles south of Fairbanks and is the only coal mine in Alaska. The coal mined at Usibelli is sub-bituminous coal and has a sulfur content of less than 1 percent. According to the US Geological Survey, coal with less than 1 percent sulfur is classified as low sulfur coal. Therefore, low sulfur coal is an available control technology.

Good Combustion Practices – Large CFB Boiler SO_2 Control Option
Large boilers that use good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining a boiler in peak operating condition is in the interest of the owner because the boiler lifespan will be optimized. Operating a boiler according to the manufacturer's recommendation will keep the boiler at the highest level of efficiency, reduce strain on the boiler, and optimize operating costs. Fuel consumption will be optimized in a well maintained and operated boiler, which will help minimize SO_2 emissions.

In the RBLC review, a number of emission units identified good combustion practices as the BACT determination for large coal-fired boilers. Good combustion practices are an available control option for reducing SO_2 emissions from the large boiler.

5.1.2 MID-SIZED DIESEL-FIRED BOILERS (EU IDs 3 AND 4) – SO_2 CONTROL OPTIONS

A review of the RBLC for mid-sized diesel-fired boilers rated between 100 and 250 MMBtu/hr identified one entry with no control technology determination. A review of larger diesel-fired boilers was conducted for the same time period, which identified only a few SO_2 BACT determinations. An RBLC review was also conducted for mid-sized natural gas-fired boilers rated between 100 and 250 MMBtu/hr because EU ID 4 is a dual fuel-fired boiler. Similar SO_2 emission control options were identified as BACT for both the larger diesel-fired boilers and mid-sized natural gas-fired boilers. The identified control options are:

- ULSD Combustion;
- Natural Gas;
- Limited Operation; and
- Good Combustion Practices.

ULSD – Mid-sized Boilers SO_2 Control Option

ULSD has a sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the boilers are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to ULSD could realize a greater than 99 percent decrease in SO_2 emissions. ULSD is an available SO_2 control option for this boiler.

Use of Natural Gas – Mid-sized Boilers SO_2 Control Option

Natural gas combustion has a lower SO_2 emission rate than standard diesel combustion and can be a preferred fuel for this reason. The availability of natural gas in Fairbanks is limited. Natural gas must be trucked to Fairbanks because no pipeline currently exists to provide natural gas to Fairbanks. EU ID 3 is not configured to burn natural gas and, because Fairbanks does not have a pipeline source, natural gas is not an available SO_2 control option for this boiler.

Only EU ID 4 has the ability to burn natural gas. Although EU ID 4 is permitted for a 10 percent capacity factor which reduces the fuel usage, a reasonable option is not to require sole usage of natural gas by this boiler. The boiler must retain the ability to burn diesel in the event that natural gas is not available. Operators have also noticed a decrease in the gas pressure as the natural gas load is increased. Maintaining a suitable gas header pressure is likely not possible if both EU IDs 3 and 4 were operating at elevated loads on natural gas.

For the above reasons, the use of only natural gas as a control technology is not an available SO_2 control option for either EU ID 3 or 4.

Limited Operation – Mid-sized Boilers SO_2 Control Option

Limited operation was not an RBLC identified control option but it is an available control technology for both EU IDs 3 and 4. EU ID 4 operates under limited operation through its restriction to a 10 percent capacity factor and shared SO_2 and NO_X emission limits of 40 tpy with EU ID 8. These two limits ultimately restrict potential SO_2 emissions from EU ID 4. With fewer available hours of operation, the annual potential SO_2 emissions are reduced. This approach is not always practical to control SO_2 emissions because not all emission units can be operated in a limited manner while sustaining the needed electrical and steam output. Limited operation is considered an available SO_2 BACT control option for both boilers EU IDs 3 and 4.

Good Combustion Practices – Mid-sized Diesel-fired Boilers SO_2 Control Option
Mid-sized boilers that use good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining a boiler in peak operating condition is in the interest of the owner because the boiler lifespan will be optimized. Operating a boiler according to the manufacturer's recommendation will keep the boiler at the highest level of efficiency, lower fuel consumption, reduce strain on the boiler, and optimize operating costs. Fuel consumption will be optimized in a well maintained and operated boiler, which will help minimize SO_2 emissions. The RBLC identified a number of emission units for which good combustion practices is the BACT determination for mid-sized boilers. Good combustion practices are an available SO_2 control option for the mid-sized boilers.

5.1.3 SMALL DIESEL-FIRED BOILERS (EU IDs 19 THROUGH 21) – SO_2 CONTROL OPTIONS

The small diesel-fired boilers are permitted to only fire ULSD. The three boilers also share an operating limit of 19,650 hours per year. A review of the RBLC for small diesel-fired boilers rated at less than 100 MMBtu/hr identified two control options. Limited operations were not indicated by the RBLC review but will also be considered:

- ULSD Combustion;
- Limited Operation; and
- Good Combustion Practices.

ULSD – Small Diesel-fired Boilers SO_2 Control Option
ULSD has a sulfur content of 0.0015 percent sulfur by weight, which is 30 times less than the allowed sulfur in standard diesel. In the RBLC, the use of ULSD was the most common technology identified for SO_2 emission control. These small boilers are only permitted to operate on ULSD. As a result, ULSD is an available control option.

Limited Operation – Small Diesel-fired Boilers SO_2 Control Option
The three small boilers share an operating limit of 19,650 hours per year. With fewer available hours of operation, the annual potential SO_2 emissions are reduced. Limited operation is an available BACT control for these boilers.

Good Combustion Practices – Small Diesel-fired Boilers SO_2 Control Option
Small boilers that use good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining a boiler in peak operating condition is in the interest of the owner because the boiler lifespan is optimized.

Operating a boiler according to the manufacturer's recommendation will keep the boiler at the highest level of efficiency, lower fuel consumption, reduce strain on the boiler, and optimize operating costs. Fuel consumption will be optimized in a well maintained and operated boiler, which will help minimize SO_2 emissions. In the RBLC review, only one emission unit identified good combustion practices as the SO_2 control technology for small boilers. Good combustion practices are an available SO_2 control option for small boilers.

5.1.4 LARGE DIESEL-FIRED ENGINE (EU ID 8) – SO_2 CONTROL OPTIONS

EU ID 8 is a large diesel-fired engine that shares a NO_X emission limit with EU ID 4. This emission limit restricts engine operation and potential SO_2 emissions. A review of the RBLC for large diesel-fired engines (process code 17.110) included several control options identified for SO_2. The following list identifies these possible SO_2 control options:

- ULSD Combustion;
- Federal Standard;
- Limited Operation; and
- Good Combustion Practices.

ULSD – Large Diesel-fired Engine SO_2 Control Option
ULSD has a sulfur content of 0.0015 percent sulfur by weight which is significantly less than the allowable sulfur in standard diesel. In the RBLC, the use of ULSD was the most common control technology identified for SO_2 emission control. The large engine can operate on ULSD, although the existing permit allows the combustion of non-ULSD. As a result, ULSD is an available SO_2 control option.

Federal Standard – Large Diesel-fired Engine SO_2 Control Option
Multiple RBLC SO_2 determinations identified that large engines are required to meet federal emission standards. The RBLC determinations indicated the many engines were to meet the emission limits in 40 CFR 60 Subpart IIII, NRE standards, or EPA certification. The 40 CFR 60 Subpart IIII limits include performance standards for stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The age, rating and size of the compression cylinder determines whether an applicable federal emission standard is included Subpart IIII, referenced to the NRE standards, or if the engine has a manufacturer's certification of meeting the required federal standards.

EU ID 8 was installed in 1999 and has not been reconstructed since that time. As a result, the reference to Subpart IIII emission standards in the RBLC is not applicable because Subpart IIII has no emission standards applicable to engines installed in 1999. On this basis, complying with the referenced federal emission standards is not an appropriate control option for EU ID 8 and will not be considered any further in this analysis.

Limited Operation – Large Diesel-fired Engine SO_2 Control Option
A number of RBLC determinations identified limiting the engine operation as the SO_2 control. With fewer hours of operation, the annual potential SO_2 emissions are reduced. This approach is not always practical for controlling SO_2 emissions because not all emission units can be operated in a limited manner while sustaining the needed electrical output commitments. The operation of EU ID 8 is restricted because the emission unit shares a SO_2 emission limit with EU ID 4, of 40 tpy. Limited operation is an available SO_2 control option for the large engine.

Good Combustion Practices – Large Diesel-fired Engine SO_2 Control Option
Large engines that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining an engine in peak operating condition is in the interest of the owner because the engine lifespan is optimized. Operating an engine according to the manufacturer's recommendation will keep the engine at the highest level of efficiency, lower fuel costs, reduce strain on the engine, and optimize operating costs. Good combustion practices are an available SO_2 control option.

5.1.5 SMALL DIESEL-FIRED ENGINE (EU ID 27) – SO_2 CONTROL OPTIONS

The small engine, EU ID 27, is permitted to fire only ULSD and is restricted to operating no more than 4,380 hours per year. Both of these restrictions are common SO_2 emission control techniques and were found in the review of the RBLC for small diesel-fired engines (process code 17.210). The following list identifies the possible SO_2 control options:

- ULSD Combustion;
- Limited Operation; and
- Good Combustion Practices.

ULSD – Small Diesel-fired Engine SO_2 Control Option
ULSD has a sulfur content of 0.0015 percent sulfur by weight which is significantly less than non-ULSD diesel. In the RBLC, the use of ULSD was the most common control technology identified for SO_2 control. EU ID 27 is only permitted to operate on ULSD. As a result, ULSD is an available control option.

Limited Operation – Small Diesel-fired Engine SO_2 Control Option
Only a few RBLC determinations identified limiting the engine operation as the SO_2 control option. With fewer available hours of operation, the annual potential SO_2 emissions are reduced. This approach is not always practical to control SO_2 emissions because not all emission units can be operated in a limited manner while sustaining the needed electrical output commitments. EU ID 27 is limited to operating no more than 4,380 hours per year. As a result, limited operation is an available SO_2 control option.

Good Combustion Practices – Small Diesel-fired Engine SO_2 Control Option
Small engines that follow good combustion practices are maintained and operated following manufacturer instructions and conventional industry practices. Maintaining an engine in peak operating condition is in the interest of the owner because the engine lifespan will be optimized. Operating an engine according to the manufacturer's recommendation will keep the engine at the highest level of efficiency, lower fuel costs, reduce strain on the engine, and optimize operating costs. Good combustion practices are an available SO_2 control option.

5.1.6 MEDICAL/PATHOLOGICAL WASTE INCINERATOR (EU ID 9A) – SO_2 CONTROL OPTIONS

SO_2 emissions for pathological waste incinerators are generally based on the type of waste material being destroyed and not the fuel that is fired to destroy the waste. The review of the RBLC for hospital, medical and infectious waste incinerators (process code 21.300) identified one control option for SO_2 based on the fuel type. EU ID 9A is permitted to fire standard diesel fuel. The fuel for EU ID 9A is supplied from a fuel tank also that supplies ULSD to EU IDs 19 through 21. The combustion of only ULSD in those emission units is required. Although not found in the RBLC review, limited operation is included in the analysis because EU ID 9A has an existing operating limit. SO_2 control options identified for consideration for the medical/pathological waste incinerator include:

- Natural Gas Combustion;
- Limited Operation;
- Good Combustion Practices; and
- ULSD Combustion.

Natural Gas – Medical/Pathological Waste Incinerator SO_2 Control Option
Natural gas combustion has a lower SO_2 emission rate than standard diesel combustion and can be a preferred fuel for this reason. The availability of natural gas in Fairbanks is limited. Natural gas must be trucked to Fairbanks because no pipeline currently exists to provide natural gas to Fairbanks. Use of natural gas was the only RBLC SO_2 incinerator control option identified in the past 10 years. The use of natural gas is an available SO_2 control option for the incinerator due to the small size of the unit.

Good Combustion Practices – Medical/Pathological Incinerator SO_2 Control Option
Incinerators that follow good combustion practices are maintained and operated according to manufacturer instructions and conventional industry practices. Maintaining an incinerator in good operating conditions is in the interest of every owner because the incinerator lifespan will be optimized and the highest level of destruction of pathological material is enabled. Good combustion practices are an available control technology.

Limited Operation – Medical/Pathological Incinerator NO_X Control Option
While the RBLC did not identify limited operation as a SO_2 control option, fewer available hours of operation does reduce the annual potential NO_X emissions. EU ID 9A is limited to 109 tpy of waste combustion. As a result, limited operation is an available control option.

ULSD – Medical/Pathological Waste Incinerator SO_2 Control Option
ULSD has a sulfur content of 0.0015 percent sulfur by weight which is significantly less than non-ULSD liquid fuel. EU ID 9A is designed to fire diesel and currently fires ULSD because the fuel line is connected to the same fuel storage tank used for EU IDs 19 through 21, emission units that are required to fire ULSD. The combustion of ULSD is an available SO_2 control option.

5.1.7 SUMMARY OF AVAILABLE SO_2 CONTROL OPTIONS

Table 5-1 summarizes the available SO_2 control options for the serious nonattainment area SO_2 emission units at UAF. The large coal and biomass-fired boiler (EU ID 113), has five available SO_2 control options. Limestone injection is part of the proposed CFB burner design. The other control options are SDA, DSI, low sulfur coal, and good combustion practices.

The only SO_2 emission control options for mid-sized diesel-fired boilers (EU IDs 3 and 4) and the small diesel-fired boilers (EU IDs 19 through 21) are the use of ULSD, limited operations, and good combustion practices.

Of the identified SO_2 control options for the large diesel-fired engine, EU ID 8, only three options are available, as shown in Table 5-1. These options are ULSD combustion, limited operation, and good combustion practices.

EU ID 27 is a small engine that is permitted for limited operation and ULSD combustion. Table 5-1 lists these two permitted control options in addition to good combustion practices.

Four options have been identified in Table 5-1 as available SO_2 control measures for the medical/pathological waste incinerator, EU ID 9A. These options are the combustion of ULSD, combustion of natural gas, limited operations, and good combustion practices.

5.2 Technical Feasibility of Available SO_2 Control Options

The following subsections describe the technical feasibility analyses for the available SO_2 control alternatives for each emission unit.

5.2.1 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – SO_2 TECHNICAL FEASIBILITY

Although not typically used for this type of coal on a CFB, the SDA and DSI control options are technically feasible add-on SO_2 control technology for the large boiler. Limestone injection is proposed as part of the CFB boiler design and is technically feasible. Because limestone injection is proposed as part of the boiler design, the SDA and DSI controls will be evaluated in addition to the limestone injection control.

Only sub-bituminous coal from the Usibelli coal mine is available in-state. The sulfur content of coal for the Usibelli mine is less than 1 percent sulfur and is therefore considered a low sulfur fuel and technically feasible.

Because limestone injection is proposed for this boiler, the SO_2 emissions will be much lower than good combustion practices emissions would be without limestone injection. Although good combustion practices are technically feasible, this technology will not be considered any further in this BACT analysis because UAF is proposing that limestone injection be used. Although eliminated from BACT consideration, good combustion practices are currently in use for other reasons.

Because both Usibelli low sulfur coal and limestone injection will be utilized for EU ID 113, these two control options will be considered together as the base case control option as shown in Table 5-2.

5.2.2 MID-SIZED DIESEL-FIRED BOILERS (EU IDs 3 AND 4) – SO_2 TECHNICAL FEASIBILITY

Both ULSD combustion and good combustion practices are technically feasible SO_2 control options being considered for these mid-sized boilers, as shown in Table 5-2. ULSD combustion would be implemented by replacing the fuel supply in the storage tanks. Limited operation is feasible and part of the EU ID 4 permitted operating restriction. EU ID 3 does not currently have an operating limit. Restricting the operation of this boiler is not possible given the emergency back-up function of EU ID 3 and the existing operating limit on EU ID 4. As a result, limited operation is not technically feasible for EU ID 3.

Because continuing the limited operation is necessary for EU ID 4, use of limited operation is proposed as the base case for SO_2 emissions for this emission unit. The limited operations option results in lower potential SO_2 emissions compared to good combustion practices with unrestricted operation. No further BACT analysis will be completed for good combustion practices. Although eliminated from BACT consideration, good combustion practices are currently in use for other reasons.

5.2.3 SMALL DIESEL-FIRED BOILERS (EU IDs 19 THROUGH 21) – SO_2 TECHNICAL FEASIBILITY

ULSD combustion is a technically feasible control option. Potential SO_2 emissions from ULSD will be less than if good combustion practices were used with standard diesel. EU IDs 19 through 21 are permitted to fire ULSD only. Although good combustion practices are technically feasible, UAF will propose the use of ULSD in conjunction with the existing hourly operating limit as BACT for these small boilers. No further BACT analysis will be completed for good combustion practices. Although eliminated from BACT consideration, good combustion practices will be implemented for other reasons.

5.2.4 LARGE DIESEL-FIRED ENGINE (EU ID 8) – SO_2 TECHNICAL FEASIBILITY

EU ID 8 is operating with limited operation due to the shared SO_2 emission limit with EU ID 4, which restricts the potential of all other pollutants including SO_2. UAF cannot reduce the operations of this engine to levels lower than the permitted restrictions because such a restriction could adversely impact facility operational needs.

Limited operation is proposed as the base case for SO_2 emissions. The limited operations option results in lower potential SO_2 emissions compared to good combustion practices with unrestricted operation. No further BACT analysis will be completed for good combustion practices. Although eliminated from BACT consideration, good combustion practices are currently in use for other reasons.

ULSD combustion would be implemented by changing the fuel supply in the storage tank. As a result, both ULSD and limited operation are technically feasible SO_2 control options being evaluated for this engine.

5.2.5 SMALL DIESEL-FIRED ENGINE (EU ID 27) – SO_2 TECHNICAL FEASIBILITY

Use of ULSD is technically feasible for this small engine because the unit is currently firing ULSD. This engine is subject to an annual operating limit. UAF cannot further reduce the operating limit on of this engine because such a restriction could adversely impact facility operational needs. Good combustion practices cannot reduce potential SO_2 emissions to levels less than ULSD combustion or limited operation. As a result, use of good combustion practices will not be considered further. Although eliminated from BACT consideration, good combustion practices are currently in use for other reasons.

ULSD combustion and limited operation will be proposed jointly as BACT based the existing permit conditions. Because no other control options are under consideration, no further SO_2 BACT analysis review is needed.

5.2.6 MEDICAL/PATHOLOGICAL WASTE INCINERATOR (EU ID 9A) – SO_2 TECHNICAL FEASIBILITY

Two fuel options are available as SO_2 emission control for the incinerator. The use of natural gas as the firing fuel for the incinerator is not a technically feasible option because Fairbanks does not have an available source of pipeline natural gas.

The other fuel option considered available as SO_2 control is the use of ULSD. An AP-42 emission factor of 2.17 lb/ton of waste is used to estimate SO_2 emissions from the incinerator. This factor does not account for whether the incinerator fuel is standard diesel, ULSD, or natural gas. As a result, the estimated SO_2 emissions from switching to ULSD will not change the 0.1 tpy PTE because the potential SO_2 emissions are largely based on the waste being incinerated. Although no reduction in potential estimated SO_2 emissions will result from the use of ULSD, as a practical matter, SO_2 emissions will be lower if ULSD is combusted in the incinerator.

The fuel line to EU ID 9A is shared with EU IDs 19 through 21, which are emission units that are required to fire ULSD. As a result, EU ID 9A is currently firing ULSD even though combustion of that fuel is not required. Calculated SO_2 emissions from EU ID 9A will not change from the current potential to emit of 0.1 tpy, but less SO_2 formation will occur because less sulfur will be bound in the fuel combusted. Although good combustion practices are technically feasible, UAF will propose the use of ULSD, in conjunction with the existing hourly operating limit, as BACT for the incinerator. No further BACT analysis will be completed for good combustion practices. Although eliminated from BACT consideration, good combustion practices will be implemented for other reasons. No further analysis will be provided for the proposed use of ULSD and limited operations as SO_2 BACT for EU ID 9A. UAF will propose that SO_2 BACT for the medical/pathological waste incinerator be the use of ULSD and limited operation.

5.2.7 SUMMARY OF SO_2 TECHNICAL FEASIBILITY

Three SO_2 control options are technically feasible for the large CFB coal and biomass-fired boiler (EU ID 113), as shown in Table 5-2. Limestone injection and the use of Usibelli low sulfur coal are both control options considered part of the base-case control option. The use of SDA and DSI are add-on controls to the joint limestone injection and low sulfur fuel base case control.

For mid-sized boiler EU ID 3, both ULSD and good combustion practices are technically feasible. For EU ID 4, ULSD and limited operation are technically feasible because this boiler currently operates on a restricted level. Limited operation is not technically feasible for EU ID 3. Good combustion practices are not included in the SO_2 BACT analysis for EU ID 4 because UAF is proposing the use of limited operation as the base-case. This option reduces SO_2 emission more than good combustion practices. Although eliminated from BACT consideration, good combustion practices are currently practiced.

Because the use of ULSD and the existing operating limit are the only technically feasible control technologies for the small boilers, these technologies will be proposed as SO_2 BACT for EU IDs 19 through 21.

The only technically feasible control options for the large engine (EU ID 8) are the use of ULSD and limited operations, which are the base-case.

SO_2 BACT for the small engine (EU ID 27) will be proposed to be the combustion of ULSD and limited operations. Both technologies are current permit requirements for this engine. No further SO_2 BACT analysis will be completed for EU ID 27.

The medical/pathological waste incinerator (EU ID 9A) has the use of ULSD and limited operation as the only technically feasible control options, as shown in Table 5-2. The use of ULSD and the existing operating limit will be proposed as SO_2 BACT. No further SO_2 BACT analysis will be completed for EU ID 9A.

5.3 Ranking of Technical Feasibility SO_2 Control Options

The following subsections rank the technically feasible control technologies for each equipment type by their ability to reduce SO_2 emissions. Table 5-3 shows the ranking of each control technology.

5.3.1 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EMISSION UNIT 113) – SO_2 RANKING OF TECHNICAL FEASIBILITY

The three technically feasible control technologies identified for EU ID 113 are limestone injection with low sulfur fuel, SDA, and DSI. Limestone injection with low sulfur fuel is part of the boiler design and is the base case control option with SDA and DSI as add-on controls. SDA with the base case has the highest level of SO_2 control at 92 percent, while DSI with the base case is estimated to control about 75 percent. Both add-on control technologies reduce potential SO_2 emissions by more than 190 tpy as shown in Table 5-3.

5.3.2 MID-SIZED DIESEL-FIRED BOILERS (EU IDs 3 AND 4) – SO_2 RANKING OF TECHNICAL FEASIBILITY

The technically feasible SO_2 control alternatives for boilers EU IDs 3 and 4 are ranked separately in Table 5-3. ULSD combustion has the ability to reduce potential SO_2 emissions by 99.7 percent because of the much lower fuel sulfur content. The amount of SO_2 emission reduction differs between the two boilers because EU ID 3 can operate at full potential, while EU ID 4 has an operating limit of 10 percent capacity, and shares 40 tpy SO_2 and NO_X emission limits with EU ID 8.

5.3.3 LARGE DIESEL-FIRED ENGINE (EU ID 8) – SO_2 RANKING OF TECHNICAL FEASIBILITY

The base-case for SO_2 emissions from the large engine (EU ID 8) is a maximum potential SO_2 emission of 40 tpy, based on the emission limit shared with EU ID 4. As shown in Table 5-3, the use of ULSD instead of standard diesel results in a 99.7 percent reduction in potential SO_2 emissions, assuming the sulfur content of standard diesel is 0.5 percent by weight.

5.4 Additional Impacts of Technically Feasible SO_2 Control Options

The following subsections describe the energy, environmental, and economic impacts associated with the alternative control options for the various equipment. The control technologies offering the greatest level of SO_2 removal are reviewed. If the control technology offering the greatest level of SO_2 control is not appropriate for BACT, then the next control technology offering the second greatest level of SO_2 removal is reviewed. Should the second best level of SO_2 control not be appropriate for BACT, then each subsequent control technology is reviewed until the base-case control is reached.

Cost estimates were prepared for the various control technologies by SCI with input from control technology vendors. The supporting cost estimates from SCI can be found in Tables 5-4 through 5-10.

5.4.1 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – SDA + (LIMESTONE INJECTION)

Energy Impacts

The large coal and biomass-fired boiler is being designed by Babcock & Wilcox with a CFB that will include limestone injection. Babcock & Wilcox was contacted for information about using an SDA on this boiler in addition to the limestone injection. Operating the SDA would require an additional 260 kW as well as additional, but not estimated, power to operate an ID fan. No other energy impacts have been estimated at this time.

Environmental Impacts

The currently designed baghouse can handle the higher loading of solids from the SDA. The system will utilize a baghouse fly ash recycle system which will activate a portion of the un-reacted lime in the fly ash. The recycled slurry, once sprayed through the atomizer, will reduce the SO_2 emissions. Although not quantified in this analysis, the material handling of hydrated lime, including slurrying and storage, could produce additional $PM_{2.5}$ emissions. The SDA byproduct would likely result in more waste being landfilled; this impact is also not quantified here.

Economic Impacts

An economic analysis has been conducted for the installation of SDA. Babcock & Wilcox was contacted to prepare costs to install an SDA on this boiler, which is in addition to the planned limestone injection system. The vendor estimated that an SDA system would cost approximately $8,000,000 to procure the equipment. These costs include two silos, one for lime and a second for recycled lime slurry, a slurry pump enclosure, and a new flue and possibly a larger ID fan to handle the increased pressure drop across the SDA and flue work. Appendix B contains the cost estimate from Babcock & Wilcox. This rough cost is shown in the total capital investment calculation, Table 5-4, as the basic equipment cost and is assumed to include all instrumentation, freight, labor, and vendor representative fees. SCI has estimated that direct installation costs are equivalent to half the basic equipment costs.

SCI has estimated that engineering, procurement and construction support services of the indirect costs are 10 percent of the total direct costs based on past project experience. The contingency costs are assumed to be 20 percent of the total direct costs based on past project experiences.

The cost effectiveness for SDA is shown in Table 5-5. Very few annual costs are included in this table. Babcock & Wilcox estimated the hydrated lime usage and electrical costs for direct annual costs estimated in the table. The indirect annual costs estimated are for administrative charges, insurance, and capital recovery. SCI estimated the administrative charges and insurance as three percent of the total capital investment based on past project experience.

Similar to the other economic impact analyses, a standardized ten year return on investment at seven percent interest rate is assumed for the capital recovery estimate based on the *OAQPS Control Cost Manual* recommendations. Because of the harsh climate, equipment in Interior Alaska experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the SDA system is reasonable.

The annualized cost effectiveness is based on the total annualized costs and the amount of SO_2 removed by the SDA system. The annualized cost effectiveness is estimated at $13,732 per ton of SO_2 removed. This cost effectiveness rate is very high, making SDA cost prohibitive.

5.4.2 LARGE CFB COAL AND BIOMASS-FIRED BOILER (EU ID 113) – DSI + (LIMESTONE INJECTION)

Energy Impacts

Babcock & Wilcox supplied information about the use of an add-on DSI on this boiler in addition to the limestone injection. Operating the DSI would require an additional 200 kW of power. No other energy impacts have been estimated at this time.

Environmental Impacts

Babcock & Wilcox expressed concern about the potential formation of a brown plume caused by the reaction of sodium with the NO_X. SCI believes this plume could be avoided by using hydrated lime. Although not quantified in this analysis, DSI systems have been shown to increase the NO_2 to NO ratio in stacks.

Economic Impacts

An economic analysis has been conducted for the installation of an add-on DSI system beyond the small DSI system designed to control HF and HCl emissions only as needed. Babcock & Wilcox supplied costs to install an add-on DSI system on this boiler in addition to the planned limestone injection and small DSI systems. The costs of the small DSI system are not included as part of the capital costs in Table 5-6. The vendor estimated that an add-on DSI system to control SO_2 emissions would cost approximately $1,500,000 to procure the equipment. Appendix B contains these cost estimates. This rough cost is shown in the total capital investment calculation as the basic equipment cost and is assumed to include all instrumentation, freight, labor, and vendor representative fees. SCI has estimated that direct installation costs are equivalent to 30 percent of the basic equipment costs.

SCI has estimated that engineering, procurement and construction support services of the indirect costs are ten percent of the total direct costs based on past project experience. The contingency costs are assumed to be 20 percent of the total direct costs based on past project experiences.

The cost effectiveness table for DSI is Table 5-7. Very few annual costs are included in this table. Babcock & Wilcox estimated the sodium bicarbonate usage and electrical costs for the add-on DSI system, which are shown as direct annual cost estimates in the table. Estimated labor and materials costs for maintaining the add-on DSI system annually have not been included at this time. These costs could be significant. Similar to the other economic impact analyses, the indirect annual costs estimated are for administrative charges, insurance and the capital recovery. SCI estimated the administrative charges and insurance as three percent of the total capital investment based on past project experience.

A standardized ten year return on investment at seven percent interest rate is assumed for the capital recovery estimate based on the *OAQPS Control Cost Manual* recommendations. Because of the harsh climate, equipment in Interior Alaska experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the DSI system is reasonable. A seven percent interest rate is used to account for the time value of money.

The annualized cost effectiveness is based on the total annualized costs and the amount of SO_2 removed by the add-on DSI system. The annualized cost effectiveness is estimated at $8,611 per ton of SO_2 removed. This cost effectiveness value is low because the estimate does not include any annual labor or maintenance materials costs. Given the lack of labor and material costs, the cost effectiveness rate is very high, making DSI cost prohibitive.

5.4.3 MID-SIZED DIESEL-FIRED BOILERS (EU IDs 3 AND 4) – ULSD

Energy Impacts

Switching fuels from standard diesel to ULSD is not expected to cause any energy impacts.

Environmental Impacts

The only anticipated environmental impact is the SO_2 reduction from this fuel switch. No additional environmental impacts are expected.

Economic Impacts

Separate economic analyses have been conducted for EU ID 3 and EU ID 4 because these boilers have different operating restrictions. EU ID 3 is allowed unlimited operation while EU ID 4 shares an SO_2 emission limit with EU ID 8 and is also subject to a 10 percent annual capacity limit.

Switching to ULSD fuel requires that standard diesel fuel in the storage tank be consumed before filling the tank with ULSD. No capital investment is required to make this switch because the same fuel tank, once cleared, can be used and the boilers are capable of burning ULSD without any additional modifications. Because no capital investment is necessary for this fuel switch, only tables estimating the annual costs and cost effectiveness has been prepared. Because EU IDs 3 and 4 have different operating limits, a table has been prepared for each of these boilers. The incremental cost increase to use ULSD instead of Diesel #2 is 28 cents per gallon based on the average difference in fuel prices during fiscal years 2014 through 2016. The only cost included in the tables is the incremental cost increase to use ULSD. Tables 5-8 and 5-9 show nearly identical cost effectiveness values of $1,084 and $1,082, respectively, per ton of SO_2 removed. The low cost effectiveness value makes the use of ULSD reasonable. As a result, the use of ULSD is proposed as SO_2 BACT for these two boilers.

5.4.4 LARGE DIESEL-FIRED ENGINE (EU ID 8) – ULSD

Energy Impacts

Switching fuels from standard diesel to ULSD is not expected to cause any energy impacts.

Environmental Impacts

The only anticipated environmental impact is the SO_2 reduction from this fuel switch. No additional environmental impacts are expected from switching fuels.

Economic Impacts

As discussed above, EU ID 8 shares an operating restriction with EU ID 4 that limits the operation of EU ID 8.

Switching to ULSD fuel requires that standard diesel fuel in the storage tank be consumed before filling the tank with ULSD. No capital investment is required to make this switch because the same fuel tank, once cleared, may be used and the boilers are capable of burning ULSD without any additional modifications. Because no capital investment is necessary for this fuel switch, only a table estimating the annual costs and cost effectiveness has been prepared. Table 5-10 shows a cost effectiveness value of $971 per ton of SO_2 removed. The low cost effectiveness value makes the use of ULSD reasonable. As a result, the use of ULSD will be proposed as SO_2 BACT for this engine.

5.4.5 SUMMARY OF BACT ANALYSIS FOR SO_2

Based on the above analysis, Table 5-11 has been prepared to summarize the SO_2 BACT economics for each type of equipment for which a cost analysis was prepared. The equipment is ranked in order of most cost-effective. No capital or annual costs are estimated for technologies proposed as the base case. Table 5-12 lists the proposed SO_2 BACT for each emission unit group.

For EU ID 113, the use of an add-on DSI or SDA system is very expensive with cost effectiveness values of $8,611 and $13,732 per ton of removed SO_2, respectively. Not all annual operating and maintenance costs are included in these cost estimates, so these cost effectiveness values are lower than the actual expected costs. EU ID 113 is proposed to operate using two of the identified SO_2 control technologies for this BACT. It seems unreasonable to expect UAF to add a third control technology on top of these proposed two controls. For this reason and that the add-on control technologies have high cost effectiveness values, SO_2 BACT for EU ID 113 is proposed to be the use of limestone injection with Usibelli's low sulfur fuel.

EU IDs 3, 4, and 8 had cost estimates prepared to review the use of ULSD as a control option. The cost effectiveness for ULSD is reasonable in a range between $971 and $1,084 per ton of SO_2 removed. The use of ULSD is proposed to be SO_2 BACT for EU ID 3. Because EU IDs 4 and 8 are subject to operating restrictions, SO_2 BACT while firing diesel is proposed to be both limited operations and the use of ULSD. SO_2 BACT for EU ID 4 while firing natural gas is proposed to be the use of limited operation because the use of ULSD is not an appropriate option.

ULSD and limited operations are proposed as SO_2 BACT for EU IDs 9A, 19 through 21, and 27. ULSD is the current fuel used for the incinerator, small boilers, and engine.

A summary of the proposed SO_2 BACT control options and associated emission rate for each emission unit is provided in Table 5-12. Although good combustion practices are not always identified as the proposed BACT determination, UAF follows these practices for their combustion equipment.

Table 5-1. UAF - Available SO_2 Control Options

Emission Unit		Available Control Options
ID	**Description**	
113	Large Coal-fired Boiler	SDA
		DSI
		Limestone Injection
		Low Sulfur Coal
		Good Combustion Practices
3 and 4	Mid-sized Diesel-fired Boilers	ULSD
		Limited Operation
		Good Combustion Practices
19 through 21	Small Diesel-fired Boilers	ULSD
		Limited Operation
		Good Combustion Practices
8	Large Diesel-fired Engine	ULSD
		Limited Operation
		Good Combustion Practices
27	Small Diesel-fired Engines	ULSD
		Limited Operation
		Good Combustion Practices
9A	Medical/Pathological Waste Incinerator	ULSD
		Limited Operation
		Good Combustion Practices
		Natural Gas

Table 5-2. UAF - Technically Feasible SO_2 Control Options

Emission Unit		Technically Feasible Control Options
ID	Description	
113	Large Coal-fired Boiler	SDA + (Limestone Injection + Low Sulfur Fuel)
		DSI + (Limestone Injection + Low Sulfur Fuel)
		Limestone Injection + Low Sulfur Fuel
3	Mid-sized Diesel and Dual Fuel-fired Boilers	ULSD
		Good Combustion Practices
4	Mid-sized Diesel and Dual Fuel-fired Boilers	ULSD
		Limited Operation
19 through 21	Small Diesel-fired Boilers	ULSD
		Limited Operation
8	Large Diesel-fired Engine	ULSD
		Limited Operation
27	Small Diesel-fired Engine	ULSD + Limited Operation
9A	Medical/Pathological Waste Incinerator	ULSD
		Limited Operation

Table 5-3. UAF - Ranking of Technically Feasible SO_2 Control Options

Emission Unit ID	Emission Unit Description	Control Technology	Control Efficiency (pct.)	SO_2 Emissions (tpy)	Emissions Reduction (tpy)
113	Large Coal and Biomass-fired Boiler	SDA + (Limestone Injection + Low Sulfur Fuel)	92	20.7	238.2
		DSI + (Limestone Injection + Low Sulfur Fuel)	75	64.7	194.2
		Limestone Injection + Low Sulfur Fuel	0	258.9	0
3	Mid-Sized Diesel-fired Boiler	ULSD	99.7	1.2	409.4
		Good Combustion Practices	0	410.6	0
4	Mid-Sized Diesel and Natural Gas-fired Boiler	ULSD + (Limited Operation)	99.7	0.1	39.9
		Limited Operation	0	40	0
8	Large Diesel-fired Engine	ULSD + (Limited Operation)	99.7	0.1	39.9
		Limited Operation	0	40	0

Table 5-4. UAF - Capital Costs for SDA on the Large Coal-fired Boiler (EU ID 113)

Shaded cells indicate user inputs.

Total Capital Investment Determination - SDA (Spray Dryer Absorber)

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 113 - CFB Boiler)

Date: 2/12/2016
Prepared By: L. Pacini
Checked By: J. Rubino
Rev: B

Capital Costs

DIRECT COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST	
(1)	**Purchased equipment and material costs**						
(a)	**Basic equipment**						
	Total SDA System	1	EA	8,000,000	$ 8,000,000		
	(per Babcock & Wilcox)						**TOTAL = $ 8,000,000**
(b)	**Instrumentation**						
	Total Instrumentation		EA		$ -		
							TOTAL = $ -
(c)	**Freight**						
	SDA Freight		% MATL COST			$ -	
							TOTAL = $ -
(d)	**Labor**						
	Labor - offsite fab		MH			$ -	
	Labor - onsite		MH			$ -	
							TOTAL = $ -
(e)	**Vendor representatives fees**						
	Fab Site Vendor Representatives fees (enter no. of days and daily rate)		Days			$ -	
	Onsite Vendor Representatives fees (enter no. of days and daily rate)		Days			$ -	
							TOTAL = $ -
Purchased Equipment and Material Cost (PEMC)		All above costs included in vendor scope.					PEMC = **$ 8,000,000**
(2)	**Direct Installation Costs**						
(a)	**Concrete**		CY		$ -		$ -
(b)	**Piling**		TON		$ -		$ -
(c)	**Structural steel**		TON		$ -		$ -
(d)	**Electrical**		LOT		$ -		$ -
(e)	**Painting**		SF		$ -		$ -
(f)	**Insulation**		LOT		$ -		$ -
(g)	**Abovegrade piping**		LF		$ -		$ -
(h)	**Functional Checkouts**						
	Functional Checkout - fab site, enter %:		% offsite fab labor			$ -	$ -
	Functional Checkout - onsite, enter %		% onsite fab labor			$ -	$ -
	Contractor Commissioning, enter %:		% of equipment total cost			$ -	$ -
Direct Installation Costs (DIC) - 1/2 x SDA Equipment Capital							DIC = **$ 4,000,000**
Total Direct Costs (TDC)							TDC = (PEMC) + (DIC) = **$ 12,000,000**
INDIRECT COSTS							
(3)	Engineering, Procurement & Construction Support Services	10%	% TDC			$ 1,200,000	
(4)	Performance tests		EA				Excluded in this estimate.
Total Indirect Costs (TIC)							TIC = **$ 1,200,000**
MANAGEMENT AND CONTINGENCY COSTS							
(5)	Unit Operator Costs		% TDC				Excluded in this estimate.
(6)	Contingency	20%	% TDC			$ 2,400,000	
Total Management and Contingency Costs (TM&CC)							TM & CC = **$ 2,400,000**
TOTAL CAPITAL INVESTMENT (TCI)							TCI = (TDC)+(TIC)+(TM&CC) = **$ 15,600,000**

Table 5-5. UAF - Annualized Costs for SDA on the Large Coal-fired Boiler (EU ID 113)

Shaded cells indicate user inputs

Total Capital Investment Determination - SDA (Spray Dryer Absorber)

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 113 - CFB Boiler)

Date: 2/12/2016
Prepared By: L. Pacini
Checked By: J. Rubino
Rev: B

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating Labor		MH		Excluded	$ -	$ -
(2)	Supervisory Labor		MH		Excluded	$ -	$ -
(3)	Maintenance Labor		MH		Excluded	$ -	$ -
(4)	Maintenance Materials		LOT		$ -	Excluded	$ -
(5)	Utilities						
	(a) Hydrated Lime:	306.60	TON	560	$ 171,696		$ 171,696
	(b) Electricity:	2277600	KWH	0.18	$ 409,968		$ 409,968
Total Direct Annual Costs (TDAC)						TDAC =	$ 581,664
INDIRECT ANNUAL COSTS							
(6)	Overhead		%		Excluded	$ -	$ -
(7)	Administrative Charges and Insurance	3.00%	% total capital			$ 468,000	$ 468,000
	Capital Recovery Factor [see inputs below]	0.1424					
(8)	Capital Recovery					CRF * TCI =	$ 2,221,089
Total Indirect Annual Costs (TIAC)						TIAC =	$ 2,689,089
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 3,270,753

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	=	238.188
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 13,732

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-6. UAF - Capital Costs for DSI on the Large Coal-fired Boiler (EU ID 113)

Shaded cells indicate user inputs.

Total Capital Investment Determination - DSI (Dry Sorbent Injection)

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 113 - CFB Boiler)

Date: 2/12/2016
Prepared By: L. Pacini
Checked By: J. Rubino
Rev: B

Capital Costs

DIRECT COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST		
(1)	**Purchased equipment and material costs**							
(a)	**Basic equipment**							
	Total DSI System	1	EA	1,500,000	$ 1,500,000			
	(per Babcock & Wilcox)						TOTAL =	$ 1,500,000
(b)	**Instrumentation**							
	Total Instrumentation		EA		$ -			
							TOTAL =	$ -
(c)	**Freight**							
	DSI System Freight		% MATL COST	0%		$ -		
							TOTAL =	$ -
(d)	**Labor**							
	Labor - offsite fab		MH			$ -		
	Labor - onsite		MH			$ -		
							TOTAL =	$ -
(e)	**Vendor representatives fees**							
	Fab Site Vendor Representatives fees (enter no. of days and daily rate)		Days			$ -		
	Onsite Vendor Representatives fees (enter no. of days and daily rate)		Days			$ -		
							TOTAL =	$ -
Purchased Equipment and Material Cost (PEMC)		All above costs included in vendor scope.					PEMC =	$ 1,500,000
(2)	**Direct Installation Costs**							
(a)	**Concrete**		CY		$ -			$ -
(b)	**Piling**		TON		$ -			$ -
(c)	**Structural steel**		TON		$ -			$ -
(d)	**Electrical**		LOT		$ -			$ -
(e)	**Painting**		SF		$ -			$ -
(f)	**Insulation**		LOT		$ -			$ -
(g)	**Abovegrade piping**		LF		$ -			$ -
(h)	**Functional Checkouts**							
	Functional Checkout - fab site, enter %:		% offsite fab labor			$ -		$ -
	Functional Checkout - onsite, enter %		% onsite fab labor			$ -		$ -
	Contractor Commissioning, enter %:		% of equipment total cost			$ -		$ -
Direct Installation Costs (DIC) - 30% x DSI Equipment Capital							DIC =	$ 450,000
Total Direct Costs (TDC)							TDC = (PEMC) + (DIC) =	$ 1,950,000
INDIRECT COSTS								
(3)	Engineering, Procurement & Construction Support Services	10%	% TDC			$ 195,000		
(4)	Performance tests		EA					Excluded in this estimate.
Total Indirect Costs (TIC)							TIC =	$ 195,000
MANAGEMENT AND CONTINGENCY COSTS								
(5)	Unit Operator Costs		% TDC					Excluded in this estimate.
(6)	Contingency	20%	% TDC			$ 390,000		
Total Management and Contingency Costs (TM&CC)							TM & CC =	$ 390,000
TOTAL CAPITAL INVESTMENT (TCI)							TCI = (TDC)+(TIC)+(TM&CC) =	$ 2,535,000

Table 5-7. UAF - Annualized Costs for DSI on the Large Coal-fired Boiler (EU ID 113)

Shaded cells indicate user inputs

Total Capital Investment Determination - DSI (Dry Sorbent Injection)

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 113 - CFB Boiler)

Date: 2/12/2016
Prepared By: L. Pacini
Checked By: J. Rubino
Rev: B

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT	UNIT COST	TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating Labor		MH		Excluded	$ -	$ -
(2)	Supervisory Labor		MH		Excluded	$ -	$ -
(3)	Maintenance Labor		MH		Excluded	$ -	$ -
(4)	Maintenance Materials		LOT		$ -	Excluded	$ -
(5)	Utilities						
	(a) Sodium Bicarbonate:	1314.00	TON	700	$ 919,800		$ 919,800
	(b) Electricity:	1752000	KWH	0.18	$ 315,360		$ 315,360
Total Direct Annual Costs (TDAC)						TDAC =	$ 1,235,160
INDIRECT ANNUAL COSTS							
(6)	Overhead		%		Excluded	$ -	$ -
(7)	Administrative Charges and Insurance	3.00%	% total capital			$ 76,050	$ 76,050
	Capital Recovery Factor [see inputs below]	0.1424					
(8)	Capital Recovery					CRF * TCI =	$ 360,927
Total Indirect Annual Costs (TIAC)						TIAC =	$ 436,977
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 1,672,137

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	=	194.175
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 8,611

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-8. UAF - Annualized Costs for ULSD on the Mid-sized Diesel-fired Boiler (EU ID 3)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project:	UAF - $PM_{2.5}$ BACT Analysis (EU ID 3 - Zurn Boiler)
Date:	2/11/2016
Prepared By:	L. Pacini
Checked By:	J. Rubino
Rev:	A

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
(a)	ULSD Costs:	1584684	MMBTU	0.28	$ 443,712		$ 443,712
Total Direct Annual Costs (TDAC)						TDAC =	$ 443,712
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges and Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC)						TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 443,712

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	=	409.4
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 1,084

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-9. UAF - Annualized Costs for ULSD on the Mid-sized Diesel-fired Boiler (EU ID 4)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 4 - Zurn Boiler)

Date: 2/11/2016
Prepared By: L. Pacini
Checked By: J. Rubino
Rev: A

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
	(a) ULSD Costs:	154227	MMBTU	0.28	$ 43,184		$ 43,184
Total Direct Annual Costs (TDAC)						TDAC =	$ 43,184
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges and Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC)						TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 43,184

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	=	39.9
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 1,082

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-10. UAF - Annualized Costs for ULSD on the Large Diesel-fired Engine (EU ID 8)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: UAF - $PM_{2.5}$ BACT Analysis (EU ID 8 - DEG)

Date: 2/11/2016
Prepared By: L. Pacini
Checked By: J. Rubino
Rev: A

Annualized Costs							
DIRECT ANNUAL COSTS		**QTY**	**UNIT**		**TOTAL MATERIALS COST**	**TOTAL LABOR COST**	**TOTAL**
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
	(a) ULSD Costs:	138331.65	MMBTU	0.28	$ 38,733		$ 38,733
Total Direct Annual Costs (TDAC)						TDAC =	$ 38,733
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges and Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC)						TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 38,733
Cost Effectiveness Summary							
TOTAL TONS SO2 AVOIDED PER YEAR						=	39.9
COST EFFECTIVENESS ($ PER TON AVOIDED)						(TAC)/(TPY) =	$ 971

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-11. UAF - SO_2 BACT Cost Effectiveness
Summary for Each Emission Unit Type

Control Technology Option	Total Installed Capital ($)	Annualized Capital Cost ($/year)	Annual O&M Cost ($/year)[2]	Cost Effectiveness ($/ton SO_2 avoided)
Large Coal-fired Engine (EU ID 113)				
DSI + (Limestone Injection + Low Sulfur Fuel)	$2,535,000	$1,672,137	$1,235,160	$8,611
SDA + (Limestone Injection + Low Sulfur Fuel)	$15,600,000	$3,270,753	$581,664	$13,732
Limestone Injection + Low Sulfur Fuel[1]	~	~	~	~
Mid-sized Diesel-fired Boiler (EU ID 3)				
ULSD	~	$443,712	$443,712	$1,084
Good Combustion Practices	~	~	~	~
Mid-sized Diesel-fired Boiler (EU ID 4)				
ULSD + (Limited Operation)	~	$43,184	$43,184	$1,082
Limited Operation[1]	~	~	~	~
Large Diesel-fired Engine (EU ID 8)				
ULSD + (Limited Operation)	~	$38,733	$38,733	$971
Limited Operation[1]	~	~	~	~

Notes:
[1] This technology is proposed as the baseline case.

Table 5-12. UAF - Proposed SO_2 BACT and Associated Emission Rate for Each Emission Unit Type

Emission Unit		Fuel	SO_2 BACT	
ID	Description		Description	Emission Rate or Fuel Sulfur Content[1]
113	Large Boiler	Coal and Biomass	Limestone Injection + Low Sulfur Fuel	0.2 lb/MMBtu
3	Mid-sized Boiler	Diesel	ULSD	15 ppmw S in fuel
4	Mid-sized Boiler	Diesel	ULSD + Limited Operation	15 ppmw S in fuel
		Natural Gas	Limited Operation	0.60 lb/MMscf
19 through 21	Small Boilers	ULSD	ULSD + Limited Operation	15 ppmw S in fuel
8	Large Engine	Diesel	ULSD + Limited Operation	15 ppmw S in fuel
27	Small Engine	ULSD	ULSD + Limited Operation	15 ppmw S in fuel
9A	Medical/Pathological Waste Incinerator	Waste	ULSD + Limited Operation	15 ppmw S in fuel

Notes:
[1] Emissions are on a per unit basis.

6.0 REFERENCES

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Appendix A: RACT/BACT/LAER Clearinghouse Search Results

Table A-1. Summary of Identified NO_X Control Technology - Large Coal and Biomass-fired Boiler, Greater Than 250 MMBtu/hr

Pollutant	Control Technology Used	Number of Coal-fired (RBLC ID 11.110) Entries (70 Total)	Number of Biomass-fired (RBLC ID 11.120) Entries (35 Total)
NO_X	SCR	15	8
	Low NOx Burners	15	1
	SNCR	16	9
	Overfired Air	13	3
	Fluidized Bed	3	-
	Staged Combustion	4	5
	Good Combustion Practices	2	4
	None	1	1
	Low Excess Air	1	-
	Flue Gas Recirculation	-	4

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-2. Summary of PM Identified Control Technology - Large Coal and Biomass-fired Boiler, Greater Than 250 MMBtu/hr

Pollutant	Control Technology Used	Number of Coal-fired (RBLC ID 11.110) Entries (77 Total)	Number of Biomass-fired (RBLC ID 11.120) Entries (53 Total)
PM	Fabric Filters	50	6
	None	10	3
	ESP	7	25
	Good Combustion Practices	5	3
	Cyclone	3	14
	Scrubber	2	-
	Settling Chamber	-	2

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-3. Summary of Identified SO_2 Control Technology - Large Coal and Biomass-fired Boiler, Greater Than 250 MMBtu/hr

Pollutant	Control Technology Used	Number of Coal-fired (RBLC ID 11.110) Entries (60 Total)	Number of Biomass-fired (RBLC ID 11.120) Entries (17 Total)
SO_2	Flue Gas Desulfurization	17	-
	Limestone Injection	15	2
	Scrubber	12	-
	Spray Dryer	7	1
	None	6	7
	Fabric Filters	2	-
	Low Sulfur Fuel	1	3
	Good Combustion Practices	-	4

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-4. RBLC Control Technology Determinations for Large Coal-fired Boilers, Greater than 250 MMBtu/hr (RBLC 11.110)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	11.11	COAL	3000	MMBTU/H	Nitrogen Dioxide (NO2)	A	SNCR	0.07	LB/MMBTU	BACT-PSD
VA-0296	VIRGINIA TECH	09/15/2005 ACT	OPERATION OF BOILER 11	11.11	COAL	146.7	mmbtu	Nitrogen Dioxide (NO2)	B	EMISSIONS CONTROLLED BY A MASS-FEED STOKER CONFIGURATION WITH LOW EXCESS AIR/STAGED COMBUSTION	0.246	LB/MMBTU	BACT-PSD
AR-0094	JOHN W. TURK JR. POWER PLANT	11/05/2008 ACT	PC BOILER	11.11	PRB SUB-BIT COAL	6000	MMBTU/H	Nitrogen Oxides (NOx)	A	SELECTIVE CATALYTIC REDUCTION (SCR)	0.067	LB/MMBTU	BACT-PSD
AZ-0055	NAVAJO GENERATING STATION	02/06/2012 ACT	PULVERIZED COAL FIRED BOILER	11.11	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	P	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	BACT-PSD
AZ-0055	NAVAJO GENERATING STATION	02/06/2012 ACT	PULVERIZED COAL FIRED BOILER	11.11	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	P	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	BACT-PSD
AZ-0055	NAVAJO GENERATING STATION	02/06/2012 ACT	PULVERIZED COAL FIRED BOILER	11.11	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	P	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	BACT-PSD
CA-1206	STOCKTON COGEN COMPANY	09/16/2011 ACT	CIRCULATING FLUIDIZED BED BOILER	11.11	COAL	730	MMBTU/H	Nitrogen Oxides (NOx)	B	LOW BED TEMPERATUR STAGED COMBUSTION; SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	50	PPM	BACT-PSD
LA-0148	ACTIVATED CARBON FACILITY	05/28/2008 ACT	MULTIPLE HEARTH FURNACES / AFTERBURNERS	11.11	COAL	7.78	LB/YR E +08	Nitrogen Oxides (NOx)	A	COMBUSTION CONTROLS (INCLUDING LOW-NOX BURNERS) AND SNCR	77.3	LB/H	BACT-PSD
LA-0176	BIG CAJUN II POWER PLANT	08/22/2005 ACT	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	11.11	SUBBITUMINOUS COAL	3518791	T/YR	Nitrogen Oxides (NOx)	B	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION	459.6	LB/H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009 ACT	BOILER	11.11	PRB COAL OR 50/50 BLEND	8190	MMBTU/H	Nitrogen Oxides (NOx)	A	LOW NOX BURNER, OVER-FIRED AIR, SELECTIVE CATALYTIC REDUCTION.	0.05	LB/MMBTU	BACT-PSD
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	01/27/2006 ACT	PULVERIZED COAL BOILER - UNIT 2	11.11	PULVERIZED COAL	4000	T/H	Nitrogen Oxides (NOx)	N	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS ARE NOT BACT FOR NOX AND SOX	0.08	LB/MMBTU	BACT-PSD
MO-0077	NORBORNE POWER PLANT	02/22/2008 ACT	MAIN BOILER	11.11	COAL	3762420	T/YR	Nitrogen Oxides (NOx)	A	SCR - SELECTIVE CATALYTIC REDUCTION LNB - LOW NOX BURNERS OFA - OVERFIRE AIR	0.065	LB/MMBTU	BACT-PSD
ND-0021	GASCOYNE GENERATING STATION	06/03/2005 ACT	BOILER, COAL-FIRED	11.11	LIGNITE	2116	MMBTU/H	Nitrogen Oxides (NOx)	B	FLUIDIZED BED COMBUSTION AND SELECTIVE NON-CATALYTIC REDUCTION (SNCR).	0.865	LB/MWH	BACT-PSD
ND-0024	SPIRITWOOD STATION	09/14/2007 ACT	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	11.11	LIGNITE	1280	MMBTU/H	Nitrogen Oxides (NOx)	A	FLUIDIZED BED COMBUSTION AND SELECTIVE NON-CATALYTIC REDUCTION	0.09	LB/MMBTU	BACT-PSD
ND-0026	M.R. YOUNG STATION	03/08/2012 ACT	Cyclone Boilers, Unit 1	11.11	Lignite	3200	MMBTU/H	Nitrogen Oxides (NOx)	B	SNCR plus separated over fire air	0.36	LB/MMBTU	BACT-PSD
ND-0026	M.R. YOUNG STATION	03/08/2012 ACT	Cyclone Boilers, Unit 2	11.11	Lignite	6300	MMBTU/H	Nitrogen Oxides (NOx)	B	SNCR plus separated over fire air	0.35	LB/MMBTU	BACT-PSD
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/2005 ACT	UNIT 2 BOILER	11.11	SUBBITUMINOUS COAL			Nitrogen Oxides (NOx)	A	SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	LB/MMBTU	BACT-PSD
NE-0049	OPPD NEBRASKA CITY STATION	02/26/2009 ACT	NCS UNIT 1	11.11	POWDER RIVER BASIN COAL	370	T/YR	Nitrogen Oxides (NOx)	P	LNB W/OVERFIRE AIR PORT SYSTEM	0.23	LB/MMBTU	BACT-PSD
NV-0036	TS POWER PLANT	05/05/2005 ACT	200 MW PC COAL BOILER	11.11	POWDER RIVER BASIN COAL	2030	MMBTU/H	Nitrogen Oxides (NOx)	B	SCR & LOW NOX BURNERS	0.067	LB/MMBTU	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/08/2009 ACT	BOILER (2), PULVERIZED COAL FIRED	11.11	PULVERIZED COAL	5191	MMBTU/H	Nitrogen Oxides (NOx)	A	SELECTIVE CATALYTIC REDUCTION	519	LB/H	BACT-PSD
OK-0118	HUGO GENERATING STA	02/09/2007 ACT	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	11.11		750	MW	Nitrogen Oxides (NOx)	A	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	LB/MMBTU	BACT-PSD
TX-0491	MEADWESTVACO TEXAS LP PULP AND PAPER MILL	01/24/2007 ACT	NO. 6 POWER BOILER	11.11	SCRAP WOOD AND BARK			Nitrogen Oxides (NOx)	P	OVERFIRE AIR	0.3	LB/MMBTU	BACT-PSD
TX-0499	SANDY CREEK ENERGY STATION	07/24/2006 ACT	PULVERIZED CAOL BOILER	11.11	COAL	8185	MMBTU/H	Nitrogen Oxides (NOx)	A	AT THIS POINT, THE FLUE GAS HAS BEEN COOLED TO THE APPROPRIATE TEMPERATURE FOR SCR, SO IT NEXT PASSES THROUGH THE SCR REACTOR, WHERE NOX IS REDUCED TO FORM NITROGEN.	1637	LB/H	BACT-PSD
TX-0518	VALERO HEAVY OIL CRACKER	11/16/2005 ACT	EMISSIONS	11.11				Nitrogen Oxides (NOx)	N		1157	LB/H	BACT-PSD
TX-0554	COLETO CREEK UNIT 2	05/03/2010 ACT	Coal-fired Boiler Unit 2	11.11	PRB coal	6670	MMBTU/H	Nitrogen Oxides (NOx)	A	low-NOx burners with OFA, Selective Catalytic Reduction	0.06	LB/MMBTU	BACT-PSD
TX-0556	HARRINGTON STATION UNIT 1 BOILER	01/15/2010 ACT	Unit 1 Boiler	11.11	Coal	3630	MMBTU/H	Nitrogen Oxides (NOx)	B	Separated overfire air windbox system; low-NOx burner tips and additional ya control to the burners.	1452	LB/H	BACT-PSD
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	02/01/2010 ACT	LMS Units 1 and 2	11.11	Coal	9061	MMBtu/H	Nitrogen Oxides (NOx)	P	Tuning of existing low-NOx firing system to induce deeper state combustion.	0.25	LB/MMBTU	BACT-PSD
TX-0577	WHITE STALLION ENERGY CENTER	12/16/2010 ACT	CFB BOILER	11.11	COAL & PET COKE	3300	MMBTU/H	Nitrogen Oxides (NOx)	B	CFB AND SNCR	0.07	LB NOX/MMBTU	BACT-PSD
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	12/30/2010 ACT	Coal-fired Boiler	11.11	Sub-bituminous coal	8307	MMBTU/H	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction	0.05	LB/MMBTU	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	08/30/2007 ACT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	11.11	WASTE COAL/BITUMINOUS BLEND			Nitrogen Oxides (NOx)	A	SNCR	0.088	LB/MMBTU	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	08/30/2007 ACT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	11.11	WASTE COAL/BITUMINOUS BLEND			Nitrogen Oxides (NOx)	A	SNCR	0.08	LB/MMBTU	BACT-PSD
VA-0309	GEORGIA PACIFIC WOOD PRODUCTS - JARRATT	05/15/2008 ACT	KEELER BOILER	11.11	COAL	86.6	MMBTU/H	Nitrogen Oxides (NOx)	B	GOOD COMBUSTION PRACTICES AND CEM SYSTEM.	51	LB/H	BACT-PSD
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	06/30/2008 ACT	2 CIRCULATING FLUIDIZED BED BOILERS	11.11	COAL AND COAL REFUSE	3132	MMBTU/H	Nitrogen Oxides (NOx)	B	SELECTIVE NON-CATALYTIC REDUCTION AND GOOD COMBUSTION PRACTICES AND CEM SYSTEM	0.07	LB/MMBTU	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	04/26/2006 ACT	CIRCULATING FLUIDIZED BED BOILER (CFB)	11.11	WASTE COAL	1070	mmbtu/h	Nitrogen Oxides (NOx)	A	SNCR	0.1	LB/MMBTU	BACT-PSD
WY-0063	WYGEN 3	02/05/2007 ACT	PC BOILER	11.11	SUBBITUMINOUS COAL	1300	MMBTU/H	Nitrogen Oxides (NOx)	A	SCR/LNB/OVERFIRE AIR	0.05	LB/MMBTU	BACT-PSD
WY-0064	DRY FORK STATION	10/15/2007 ACT	PC BOILER (ES1-01)	11.11	COAL			Nitrogen Oxides (NOx)	A	LOW NOX BURNERS AND SCR	0.05	LB/MMBTU	BACT-PSD
PA-0247	BEECH HOLLOW POWER PROJECT	04/01/2005 ACT	COAL FIRED CFB	11.11	WASTE COAL			Nitrogen Oxides (NOx)	A	SNCR EMPLOYED TO MINIMIZE NOX EMISSIONS. FACILITY WILL BE EQUIPPED WITH NOX CEM TO MONITOR EXHAUST GAS STREAM.	0.08	LB/MMBTU	LAER
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	07/08/2005 ACT	2 CFB BOILERS	11.11	WASTE COAL	358	T/H (each)	Nitrogen Oxides (NOx)	A	SNCR, NOX CEM	0.08	LB/MMBTU	LAER
PA-0249	RIVER HILL POWER COMPANY, LLC	07/21/2005 ACT	CFB BOILER	11.11	WASTE COAL			Nitrogen Oxides (NOx)	A	SNCR INSTALLED. NOX EMISSIONS MONITORED BY CEM	880.2	T/YR	LAER
PA-0257	SUNNYSIDE ETHANOL,LLC	05/07/2007 ACT	CFB BOILER	11.11	COAL	496.8	MMBTU/H	Nitrogen Oxides (NOx)	A	SNCR	0.1	LB/MMBTU	LAER
PA-0259	CAMBRIA COKE CO.	08/25/2006 ACT	PYROPOWER UNIT A	11.11	COAL			Nitrogen Oxides (NOx)	P	COMBUSTION STAGING	0.3	LB/MMBTU	LAER
PA-0259	CAMBRIA COKE CO.	08/25/2006 ACT	PYROPOWER UNIT B	11.11	COAL			Nitrogen Oxides (NOx)	P	COMBUSTION STAGING	0.3	LB/MMBTU	LAER
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	01/27/2006 ACT	PULVERIZED COAL BOILER - UNIT 1	11.11	COAL	4000	T/H	Nitrogen Oxides (NOx)	N		0.1	LB/MMBTU	N/A
OH-0314	SMART PAPERS HOLDINGS, LLC	01/31/2008 ACT	PULVERIZED DRY BOTTOM BOILER	11.11	COAL	420	MMBTU/H	Nitrogen Oxides (NOx)	N		267	T/YR	N/A
OH-0314	SMART PAPERS HOLDINGS, LLC	01/31/2008 ACT	SPREADER STOKER COAL-FIRED BOILER	11.11	COAL	249	MMBTU/H	Nitrogen Oxides (NOx)	N		163.5	LB/H	N/A
TX-0489	SOUTHWESTERN PUBLIC SERVICE COMPANY-HARRINGTON STATION	10/17/2006 ACT	UNIT 3 BOILER	11.11	PBR COAL	3870	MMBtu/h	Nitrogen Oxides (NOx)	A	LOW NOX BURNERS, SEPARATED OVERFIRE AIR WINDBOX, WITH ADDITIONAL YAW CONTROL OF THE BURNERS FOR ADDITIONAL NOX CONTROL	0.3	LB/MMBTU	Other Case-by-Case
CA-1158	CELITE	06/11/2007 ACT	NON-METALLIC MINERAL PROCESSING (EXCLUDING ROCK, SAND AND AGGREGATE)	11.11	ANTHRACITE COAL	16	16,266 SCFM / 3	Particulate Matter (PM)	A	BAHOUSES. TRIBOELECTRIC OPACITY MONITOR ON ONE UNIT	0.005	GR/DSCF	BACT-PSD
CO-0057	COMANCHE STATION	07/05/2005 ACT	PC BOILER - UNIT 3	11.11	SUB-BITUMINOUS COAL	7421	MMBTU/H	Particulate Matter (PM)	A	BAGHOUSE	0.013	LB/MMBTU	BACT-PSD
IL-0107	DALLMAN POWER PLANT	08/10/2006 ACT	DALLMAN 4 ELECTRICAL GENERATING UNIT	11.11				Particulate Matter (PM)	A	CONVENTIONAL DRY ESP, CONVENTIONAL SCRUBBER AND WET ESP.	0.035	LB/MMBTU	BACT-PSD
ND-0021	GASCOYNE GENERATING STATION	06/03/2005 ACT	BOILER, COAL-FIRED	11.11	LIGNITE	2116	MMBTU/H	Particulate Matter (PM)	A	BAGHOUSE	0.0167	LB/MMBTU	BACT-PSD
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/2005 ACT	TRIPPER DUST COLLECTOR (EP-105)	11.11				Particulate Matter (PM)	N	DUST COLLECTOR IS THE CONTROL	0.01	GRAINS/DSCF	BACT-PSD
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/2005 ACT	RECYCLED ASH STORAGE (EP-203)	11.11				Particulate Matter (PM)	N		0.01	GRAINS/DSCF	BACT-PSD
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/2005 ACT	TRIPPER DUST COLLECTOR (EP-106)	11.11				Particulate Matter (PM)	N	DUST COLLECTOR IS THE CONTROL DEVICE	0.01	GR/DSCF	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/2005 ACT	SDA LIME STORAGE EXHAUST (EP-202)	11.11				Particulate Matter (PM)	N		0.01	GR/DSCF	BACT-PSD
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/2005 ACT	FLY ASH WASTE DUST COLLECTOR (EP-211)	11.11				Particulate Matter (PM)	N	DUST COLLECTOR IS THE CONTROL	0.01	GR/DSCF	BACT-PSD
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/2005 ACT	UNIT 2 BOILER	11.11	SUBBITUMINOUS COAL			Particulate Matter (PM)	A	FABRIC FILTER BAGHOUSES	0.018	LB/MMBTU	BACT-PSD
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/2005 ACT	FLY ASH WASTE STORAGE VENT (EP-204)	11.11				Particulate Matter (PM)	N		0.01	GR/DSCF	BACT-PSD
TX-0518	VALERO HEAVY OIL CRACKER	11/16/2005 ACT	EMISSIONS	11.11				Particulate Matter (PM)	N		272	LB/H	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	08/30/2007 ACT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	11.11	WASTE COAL/BITUMINOU S BLEND			Particulate Matter (PM)	A	PULSE-JET FABRIC FILTER BAGHOUSE	0.03	LB/MMBTU	BACT-PSD
VA-0309	GEORGIA PACIFIC WOOD PRODUCTS - JARRATT	05/15/2008 ACT	KEELER BOILER	11.11	COAL	86.6	MMBTU/H	Particulate Matter (PM)	B	2 MULITCYCLONES AND GOOD COMBUSTION PRACTICES.	20	LB/H	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	04/26/2006 ACT	CIRCULATING FLUIDIZED BED BOILER (CFB)	11.11	WASTE COAL	1070	mmbtu/h	Particulate Matter (PM)	A	BAGHOUSE	0.03	LB/MMBTU	BACT-PSD
ND-0024	SPIRITWOOD STATION	09/14/2007 ACT	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	11.11	LIGNITE	1280	MMBTU/H	Particulate Matter (PM), Organic Condensables	A	SPRAY DRYER AND BAGHOUSE	0.018	LB/MMBTU	BACT-PSD
IL-0107	DALLMAN POWER PLANT	08/10/2006 ACT	DALLMAN 4 ELECTRICAL GENERATING UNIT	11.11				Particulate matter, filterable (FPM)	A	CONVENTIONAL DRY ESP FOLLOWED BY WET ESP.	0.012	LB/MMBTU	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	11.11	COAL	3000	MMBTU/H	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.09	LB/MMBTU	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009 ACT	BOILER	11.11	PRB COAL OR 50/50 BLEND	8190	MMBTU/H	Particulate matter, filterable (FPM)	A	FABRIC FILTER	0.011	LB/MMBTU	BACT-PSD
ND-0024	SPIRITWOOD STATION	09/14/2007 ACT	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	11.11	LIGNITE	1280	MMBTU/H	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.015	LB/MMBTU	BACT-PSD
TX-0577	WHITE STALLION ENERGY CENTER	12/16/2010 ACT	CFB BOILER	11.11	COAL & PET COKE	3300	MMBTU/H	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.01	LB PM FILT/MMBT U	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	08/30/2007 ACT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	11.11	WASTE COAL/BITUMINOU S BLEND			Particulate matter, filterable (FPM)	A	PULSE-JET FABRIC FILTER BAGHOUSE	0.012	LB/MMBTU	BACT-PSD
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	06/30/2008 ACT	2 CIRCULATING FLUIDIZED BED BOILERS	11.11	COAL AND COAL REFUSE	3132	MMBTU/H	Particulate matter, filterable (FPM)	P	GOOD COMBUSTIONS PRACTICES AND BAGHOUSE	0.01	LB/MMBTU	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	04/26/2006 ACT	CIRCULATING FLUIDIZED BED BOILER (CFB)	11.11	WASTE COAL	1070	mmbtu/h	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.015	LB/MMBTU	BACT-PSD
WY-0063	WYGEN 3	02/05/2007 ACT	PC BOILER	11.11	SUBBITUMINOUS COAL	1300	MMBTU/H	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.012	LB/MMBTU	BACT-PSD
AZ-0050	CORONADO GENERATING STATION	01/22/2009 ACT	UNIT 1	11.1	COAL	4719	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	ESP	0.03	LB/MMBTU	BACT-PSD
AR-0094	JOHN W. TURK JR. POWER PLANT	11/05/2008 ACT	PC BOILER	11.11	PRB SUB-BIT COAL	6000	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER	0.012	LB/MMBTU	BACT-PSD
AZ-0050	CORONADO GENERATING STATION	01/22/2009 ACT	UNIT 2	11.11	COAL	4719	MMBTU	Particulate matter, filterable < 10 µ (FPM10)	A	ESP	0.03	LB/MMBTU	BACT-PSD
CO-0055	LAMAR LIGHT & POWER POWER PLANT	02/03/2006 ACT	CIRCULATING FLUIDIZED BED BOILER	11.11	COAL COAL (BITUMINOUS/SUB BITUMINOUS)	501.7	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	N	HIGH EFFICIENCY(MEMBRANE) LINED FABRIC FILTER BAGHAUSE FOR FILTEARABLE PARTICULATE MATTER. MAXIMIZATION OF HEAT EXTRACTION FROM COMBUSTION GASES PRIOR TO BAGHAUSE	0.012	LB/MMBTU	BACT-PSD
CO-0057	COMANCHE STATION	07/05/2005 ACT	PC BOILER - UNIT 3	11.11	SUB-BITUMINOUS COAL	7421	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.012	LB/MMBTU	BACT-PSD
FL-0295	CRYSTAL RIVER POWER PLANT	05/18/2007 ACT	FFFSG UNITS 4 AND 5	11.11	COAL	760	MW	Particulate matter, filterable < 10 µ (FPM10)	A	MODIFIED ESP (IMPROVEMENTS)	0.03	LB/MMBTU	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	11.11	COAL	3000	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.09	LB/MMBTU	BACT-PSD
LA-0176	BIG CAJUN II POWER PLANT	08/22/2005 ACT	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	11.11	SUBBITUMINOUS COAL	3518791	T/YR	Particulate matter, filterable < 10 µ (FPM10)	A	ESP AND BAGHOUSE IN SERIES CONFIGURATION	78.79	LB/H	BACT-PSD
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	01/27/2006 ACT	PULVERIZED COAL BOILER - UNIT 2	11.11	PULVERIZED COAL	4000	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	KCPL SHALL INSTALL A FABRIC FILTRATION SYSTEM (BAGHOUSE) FOR THE UNIT 2 BOILER TO REDUCE PM10 EMISSIONS.	0.0236	LB/MMBTU	BACT-PSD
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	01/27/2006 ACT	PULVERIZED COAL BOILER - UNIT 1	11.11	COAL	4000	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.0244	LB/MMBTU	BACT-PSD
MO-0077	NORBORNE POWER PLANT	02/22/2008 ACT	MAIN BOILER	11.11	COAL	3762420	T/YR	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTRATION SYSTEM (BAGHOUSE)	0.018	LB/MMBTU	BACT-PSD
ND-0021	GASCOYNE GENERATING STATION	06/03/2005 ACT	BOILER, COAL-FIRED	11.11	LIGNITE	2116	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.013	LB/MMBTU	BACT-PSD
ND-0024	SPIRITWOOD STATION	09/14/2007 ACT	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	11.11	LIGNITE	1280	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.012	LB/MMBTU	BACT-PSD
NV-0036	TS POWER PLANT	05/05/2005 ACT	200 MW PC COAL BOILER	11.11	POWDER RIVER BASIN COAL	2030	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER DUST COLLECTION	0.012	LB/MMBTU	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/08/2009 ACT	BOILER (2), PULVERIZED COAL FIRED	11.11	PULVERIZED COAL	5191	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE IN COMBINATION WITH A WET ELECTROSTATIC PRECIPITATOR (WESP)	125	LB/H	BACT-PSD
OK-0118	HUGO GENERATING STA	02/09/2007 ACT	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	11.11		750	MW	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER BAGHOUSE	0.015	LB/MMBTU	BACT-PSD
PA-0247	BEECH HOLLOW POWER PROJECT	04/01/2005 ACT	COAL FIRED CFB	11.11	WASTE COAL			Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.012	LB/MMBTU	BACT-PSD
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	07/08/2005 ACT	2 CFB BOILERS	11.11	WASTE COAL	358	T/H (each)	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE, 289.7 TPY WAS DETERMINED BY EPA METHODS 201,201A,202. PROVISION TO INCREASE IF CAN'T MEET LIMIT BECAUSE OF CONDENSIBLES PER METHOD 202	0.012	LB/MMBTU	BACT-PSD
PA-0249	RIVER HILL POWER COMPANY, LLC	07/21/2005 ACT	CFB BOILER	11.11	WASTE COAL			Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	125.7	T/YR	BACT-PSD
PA-0257	SUNNYSIDE ETHANOL,LLC	05/07/2007 ACT	CFB BOILER	11.11	COAL	496.8	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	CYCLONE AND BAGHOUSE	0.01	LB/MMBTU	BACT-PSD
PA-0259	CAMBRIA COKE CO.	08/25/2006 ACT	PYROPOWER UNIT A	11.11	COAL			Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER	16.8	LB/H	BACT-PSD
PA-0259	CAMBRIA COKE CO.	08/25/2006 ACT	PYROPOWER UNIT B	11.11	COAL			Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	16.8	LB/H	BACT-PSD
TX-0491	MEADWESTVACO TEXAS LP PULP AND PAPER MILL	01/24/2007 ACT	NO. 6 POWER BOILER	11.11	SCRAP WOOD AND BARK			Particulate matter, filterable < 10 µ (FPM10)	B	VENTURI WET SCRUBBER	0.1	LB/MMBTU	BACT-PSD
TX-0499	SANDY CREEK ENERGY STATION	07/24/2006 ACT	PULVERIZED CAOL BOILER	11.11	COAL	8185	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	N		123	LB/H	BACT-PSD
TX-0554	COLETO CREEK UNIT 2	05/03/2010 ACT	Coal-fired Boiler Unit 2	11.11	PRB coal	6670	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	fabric filter	0.012	LB/MMBTU	BACT-PSD
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	12/30/2010 ACT	Coal-fired Boiler	11.11	Sub-bituminous coal	8307	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	Fabric Filter	0.012	LB/MMBTU	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	08/30/2007 ACT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	11.11	WASTE COAL/BITUMINOU S BLEND			Particulate matter, filterable < 10 µ (FPM10)	A	PULSE-JET FABRIC FILTER BAGHOUSE	0.012	LB/MMBTU	BACT-PSD
VA-0296	VIRGINIA TECH	09/15/2005 ACT	OPERATION OF BOILER 11	11.11	COAL	146.7	mmbtu	Particulate matter, filterable < 10 µ (FPM10)	A	BAG HOUSE EQUIPED WITH CEM	0.018	LB/MMBTU	BACT-PSD
VA-0309	GEORGIA PACIFIC WOOD PRODUCTS - JARRATT	05/15/2008 ACT	KEELER BOILER	11.11	COAL	86.6	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	B	TWO MULTICYCLONES AND GOOD COMBUSTION PRACTICES.	14.5	LB/H	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	04/26/2006 ACT	CIRCULATING FLUIDIZED BED BOILER (CFB)	11.11	WASTE COAL	1070	mmbtu/h	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.03	LB/MMBTU	BACT-PSD
WY-0064	DRY FORK STATION	10/15/2007 ACT	PC BOILER (ES1-01)	11.11	COAL			Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER (BAGHOUSE)	0.012	LB/MMBTU	BACT-PSD
TX-0554	COLETO CREEK UNIT 2	05/03/2010 ACT	Coal-fired Boiler Unit 2	11.11	PRB coal	6670	MMBTU/H	Particulate matter, total (TPM)	A	fabric filter, spray dry adsorber for acid gases	0.025	LB/MMBTU	BACT-PSD
TX-0577	WHITE STALLION ENERGY CENTER	12/16/2010 ACT	CFB BOILER	11.11	COAL & PET COKE	3300	MMBTU/H	Particulate matter, total (TPM)	A	LSD, ACTIVATED CARBON, BAGHOUSE	0.018	LB PM TOT/MMBT U	BACT-PSD
VA-0312	SPRUANCE GENCO, LLC	01/23/2009 ACT	ELECTRIC GENERATION	11.11	COAL	124392	T/YR	Particulate matter, total (TPM)	B	CEM SYSTEM AND BAGHOUSE WITH WET MISTING FOLLOWED BY A DRY UNLOADER. FABRIC FILTERS.	0.3	LB/H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009 ACT	BOILER	11.11	PRB COAL OR 50/50 BLEND	8190	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	A	FABRIC FILTER, HYDRATED LIME INJECTION	0.024	LB/MMBTU	BACT-PSD
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	12/30/2010 ACT	Coal-fired Boiler	11.11	Sub-bituminous coal	8307	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	A	Fabric filter and wet scrubber	0.025	LB/MMBTU	BACT-PSD
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	06/30/2008 ACT	2 CIRCULATING FLUIDIZED BED BOILERS	11.11	COAL AND COAL REFUSE	3132	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	P	GOOD COMBUSTION PRACTICES AND BAGHOUSE	0.012	LB/MMBTU	BACT-PSD
VA-0312	SPRUANCE GENCO, LLC	01/23/2009 ACT	ELECTRIC GENERATION	11.11	COAL	124392	T/YR	Particulate matter, total < 10 µ (TPM10)	B	CEM SYSTEM AND BAGHOUSE WITH WET MISTING FOLLOWED BY A DRY UNLOADER. FABRIC FILTERS.	0.3	LB/H	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	06/30/2008 ACT	2 CIRCULATING FLUIDIZED BED BOILERS	11.11	COAL AND COAL REFUSE	3132	MMBTU/H	Particulate matter, total < 2.5 µ (TPM2.5)	P	GOOD COMBUSTION PRACTICES AND BAGHOUSE	0.012	LB/MMBTU	BACT-PSD
OH-0314	SMART PAPERS HOLDINGS, LLC	01/31/2008 ACT	PULVERIZED DRY BOTTOM BOILER	11.11	COAL	420	MMBTU/H	Particulate Matter (PM)	N		0.11	LB/MMBTU	N/A
OH-0314	SMART PAPERS HOLDINGS, LLC	01/31/2008 ACT	SPREADER STOKER COAL-FIRED BOILER	11.11	COAL	249	MMBTU/H	Particulate Matter (PM)	N		0.11	LB/MMBTU	N/A
OH-0314	SMART PAPERS HOLDINGS, LLC	01/31/2008 ACT	SPREADER STOKER COAL-FIRED BOILER	11.11	COAL	249	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	N		0.072	LB/MMBTU	N/A
TX-0489	SOUTHWESTERN PUBLIC SERVICE COMPANY-HARRINGTON STATION	10/17/2006 ACT	UNIT 3 BOILER	11.11	PBR COAL	3870	MMBtu/h	Particulate matter, filterable < 10 µ (FPM10)	B	COAL CRUSHERS OPERATE AT BELOW ATMOSPHERIC PRESSURE WITH COAL DUST CONTROLLED	0.09	LB/MMBTU	Other Case-by-Case
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/08/2009 ACT	BOILER (2), PULVERIZED COAL FIRED	11.11	PULVERIZED COAL	5191	MMBTU/H	Particulate matter, filterable (FPM)	A	BAGHOUSE IN COMBINATION WITH A WET ELECTROSTATIC PRECIPITATOR (WESP)	0.012	LB/MMBTU	MACT
AR-0094	JOHN W. TURK JR. POWER PLANT	11/05/2008 ACT	PC BOILER	11.11	PRB SUB-BIT COAL	6000	MMBTU/H	Sulfur Dioxide (SO2)	A	DRY FLUE GAS DESULFURIZATION (SPRAY DRY ADSORBER)	0.08	LB/MMBTU	BACT-PSD
CA-1206	STOCKTON COGEN COMPANY	09/16/2011 ACT	CIRCULATING FLUIDIZED BED BOILER	11.11	COAL	730	MMBTU/H	Sulfur Dioxide (SO2)	P	LIMESTONE INJECTION W/ A MINIMUM REMOVAL EFFICIENCY OF 70% (3-HR AVG) TO BE MAINTAINED AT ALL TIMES	59	LB/H	BACT-PSD
CO-0055	LAMAR LIGHT & POWER POWER PLANT	02/03/2006 ACT	CIRCULATING FLUIDIZED BED BOILER	11.11	COAL (BITUMINOUS/SUB-BITUMINOUS)	501.7	MMBTU/H	Sulfur Dioxide (SO2)	P	LIMESTONE INJECTION FOR S02 CONTROL . SAND IS USED AS INERT MATERIAL FOR REGULATION OF CIRCULATING BED TEMPERATURE	0.103	LB/MMBTU	BACT-PSD
IA-0091	OTTUMWA GENERATING STATION	02/27/2007 ACT	BOILER #1	11.11	COAL	6370	MMBTU/H	Sulfur Dioxide (SO2)	P	LOW SULFUR COAL	1.2	LB/MMBTU	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	11.11	COAL	3000	MMBTU/H	Sulfur Dioxide (SO2)	A	LIMESTONE INJECTION (CFB)AND A FLASH DRYER ABSORBER WITH FRESH LIME INJECTION	0.075	LB/MMBTU	BACT-PSD
LA-0148	ACTIVATED CARBON FACILITY	05/28/2008 ACT	MULTIPLE HEARTH FURNACES / AFTERBURNERS	11.11	COAL	7.78	LB/YR E +08	Sulfur Dioxide (SO2)	A	SPRAY DRYER ABSORBER (SDA) SYSTEM	101.2	LB/H	BACT-PSD
LA-0176	BIG CAJUN II POWER PLANT	08/22/2005 ACT	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	11.11	SUBBITUMINOUS COAL	3518791	T/YR	Sulfur Dioxide (SO2)	A	OPTION 1: SEMI-DRY LIME SCRUBBER OPTION 2: WET FLUE GAS DESULFURIZATION SYSTEM	656.6	LB/H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009 ACT	BOILER	11.11	PRB COAL OR 50/50 BLEND	8190	MMBTU/H	Sulfur Dioxide (SO2)	B	LIMESTONE FORCED OXIDATION, WET FLUIDIZED GAS DESULFURIZATION (FGD) AND LOW SULFUR COAL.	0.06	LB/MMBTU	BACT-PSD
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	01/27/2006 ACT	PULVERIZED COAL BOILER - UNIT 2	11.11	PULVERIZED COAL	4000	T/H	Sulfur Dioxide (SO2)	N	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS ARE NOT BACT FOR NOX AND SOX	0.09	LB/MMBTU	BACT-PSD
MO-0077	NORBORNE POWER PLANT	02/22/2008 ACT	MAIN BOILER	11.11	COAL	3762420	T/YR	Sulfur Dioxide (SO2)	A	DRY FLUE GAS DESUL	0		BACT-PSD
ND-0021	GASCOYNE GENERATING STATION	06/03/2005 ACT	BOILER, COAL-FIRED	11.11	LIGNITE	2116	MMBTU/H	Sulfur Dioxide (SO2)	B	LIMESTONE INJECTION WITH A SPRAY DRYER.	0.038	LB/MMBTU	BACT-PSD
ND-0024	SPIRITWOOD STATION	09/14/2007 ACT	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	11.11	LIGNITE	1280	MMBTU/H	Sulfur Dioxide (SO2)	A	LIMESTONE INJECTION INTO THE UNIT WITH A SPRAY DRYER FOLLOWING.	0.06	LB/MMBTU	BACT-PSD
NE-0031	OPPD - NEBRASKA CITY STATION	03/09/2005 ACT	UNIT 2 BOILER	11.11	SUBBITUMINOUS COAL			Sulfur Dioxide (SO2)	A	DRY FLUE GAS DESULFURIZATION & FABRIC FILTER	0.095	LB/MMBTU	BACT-PSD
NV-0036	TS POWER PLANT	05/05/2005 ACT	200 MW PC COAL BOILER	11.11	POWDER RIVER BASIN COAL	2030	MMBTU/H	Sulfur Dioxide (SO2)	A	LIME SPRAY SPRAY DRY SCRUBBER	0.09	LB/MMBTU	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/08/2009 ACT	BOILER (2), PULVERIZED COAL FIRED	11.11	PULVERIZED COAL	5191	MMBTU/H	Sulfur Dioxide (SO2)	A	WET FLUE GAS DESULFURIZATION (FGS) EITHER LIME OR AMMONIA-BASED	1246	LB/H	BACT-PSD
OH-0314	SMART PAPERS HOLDINGS, LLC	01/31/2008 ACT	PULVERIZED DRY BOTTOM BOILER	11.11	COAL	420	MMBTU/H	Sulfur Dioxide (SO2)	N		1.7	LB/MMBTU	BACT-PSD
OH-0314	SMART PAPERS HOLDINGS, LLC	01/31/2008 ACT	SPREADER STOKER COAL-FIRED BOILER	11.11	COAL	249	MMBTU/H	Sulfur Dioxide (SO2)	N		1.7	LB/H	BACT-PSD
OK-0118	HUGO GENERATING STA	02/09/2007 ACT	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)	11.11		750	MW	Sulfur Dioxide (SO2)	A	WET LIMESTONE FLUE GAS DESULFURIZATION	0.065	LB/MMBTU	BACT-PSD
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	07/08/2005 ACT	2 CFB BOILERS	11.11	WASTE COAL	358	T/H (each)	Sulfur Dioxide (SO2)	A	EMISSION RESTRICTION, LIMESTONE INJECTION PLUS A DRY POLISHING SCRUBBER, EMISSION MONITORED BY CEM WHICH IS BASIS FOR EFFICIENCY CONTROL	0.156	LB/MMBTU	BACT-PSD
PA-0249	RIVER HILL POWER COMPANY, LLC	07/21/2005 ACT	CFB BOILER	11.11	WASTE COAL			Sulfur Dioxide (SO2)	A	DRY FLUE GAS DESULFURIZATION SYSYTEM	0.274	LB/MMBTU	BACT-PSD
PA-0257	SUNNYSIDE ETHANOL,LLC	05/07/2007 ACT	CFB BOILER	11.11	COAL	496.8	MMBTU/H	Sulfur Dioxide (SO2)	A	LIMESTONE INJECTION AND ADD ON DRY FLUE GAS DESULFEDRIZATION, CEM	0.2	LB/MMBTU	BACT-PSD
PA-0259	CAMBRIA COKE CO.	08/25/2006 ACT	PYROPOWER UNIT A	11.11	COAL			Sulfur Dioxide (SO2)	A	LIME INJECTION, SPRAY DRYER AND ADSORBER SYSTEM	556	LB/H	BACT-PSD
PA-0259	CAMBRIA COKE CO.	08/25/2006 ACT	PYROPOWER UNIT B	11.11	COAL			Sulfur Dioxide (SO2)	A	LIME INJECTION/SPRAY DRYER/ADSORBER SYSTEM	556	LB/H	BACT-PSD
TX-0499	SANDY CREEK ENERGY STATION	07/24/2006 ACT	PULVERIZED CAOL BOILER	11.11	COAL	8185	MMBTU/H	Sulfur Dioxide (SO2)	N		2456	LB/H	BACT-PSD
TX-0518	VALERO HEAVY OIL CRACKER	11/16/2005 ACT	EMISSIONS	11.11				Sulfur Dioxide (SO2)	N		510	LB/H	BACT-PSD
TX-0554	COLETO CREEK UNIT 2	05/03/2010 ACT	Coal-fired Boiler Unit 2	11.11	PRB coal	6670	MMBTU/H	Sulfur Dioxide (SO2)	A	Spray Dry Adsorber/Fabric Filter	0.06	LB/MMBTU	BACT-PSD
TX-0577	WHITE STALLION ENERGY CENTER	12/16/2010 ACT	CFB BOILER	11.11	COAL & PET COKE	3300	MMBTU/H	Sulfur Dioxide (SO2)	A	LIMESTONE BED CFB AND LIME SPRAY DRYER PERMIT DESIGN SULFUR CONTENT OF ILL BASIN COAL IS 3.9 WT% AND OF PET COKE 4.3 AVG/6.0 MAX HI WEIGHTING OF LIMITS USED FOR FUEL BLENDING	0.114	LB SO2/MMBTU	BACT-PSD
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	12/30/2010 ACT	Coal-fired Boiler	11.11	Sub-bituminous coal	8307	MMBTU/H	Sulfur Dioxide (SO2)	A	Wet limestone scrubber	0.06	LB/MMBTU	BACT-PSD
TX-0601	GIBBONS CREEK STEAM ELECTRIC STATION	10/28/2011 ACT	Boiler	11.11	Coal	5060	MMBtu/h	Sulfur Dioxide (SO2)	A	Wet Flue Gas Desulfurization	1.2	LB/MMBTU	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	08/30/2007 ACT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	11.11	WASTE COAL/BITUMINOUS BLEND			Sulfur Dioxide (SO2)	A		0.055	LB/MMBTU	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	08/30/2007 ACT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	11.11	WASTE COAL/BITUMINOUS BLEND			Sulfur Dioxide (SO2)	A	LIMESTONE INJECTION SYSTEM DRY SO2 SCRUBBER (SPRAY DRY ABSORBER)	0.055	LB/MMBTU	BACT-PSD
VA-0296	VIRGINIA TECH	09/15/2005 ACT	OPERATION OF BOILER 11	11.11	COAL	146.7	mmbtu	Sulfur Dioxide (SO2)	A	DRY SCRUBBER FLUE GAS DESULFURIZATION SYSTEM AND CEMS	0.161	LB/MMBTU	BACT-PSD
VA-0309	GEORGIA PACIFIC WOOD PRODUCTS - JARRATT	05/15/2008 ACT	KEELER BOILER	11.11	COAL	86.6	MMBTU/H	Sulfur Dioxide (SO2)	B	GOOD COMBUSTION PRACTICES LOW SULFUR CONTENT COAL AND CEM SYSTEM.	0		BACT-PSD
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	06/30/2008 ACT	2 CIRCULATING FLUIDIZED BED BOILERS	11.11	COAL AND COAL REFUSE	3132	MMBTU/H	Sulfur Dioxide (SO2)	B	LIMESTONE INJECTION AND FLUE GAS DESULFURIZATION AND CEM SYSTEM	0.035	LB/MMBTU	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	04/26/2006 ACT	CIRCULATING FLUIDIZED BED BOILER (CFB)	11.11	WASTE COAL	1070	mmbtu/h	Sulfur Dioxide (SO2)	B	LIME INJECTION AND FLASH DRYER ABSORBER (FDA)	0.14	LB/MMBTU	BACT-PSD
WY-0063	WYGEN 3	02/05/2007 ACT	PC BOILER	11.11	SUBBITUMINOUS COAL	1300	MMBTU/H	Sulfur Dioxide (SO2)	A	DRY FGD	0.09	LB/MMBTU	BACT-PSD
WY-0064	DRY FORK STATION	10/15/2007 ACT	PC BOILER (ES1-01)	11.11	COAL			Sulfur Dioxide (SO2)	A	CIRCULATING DRY SCRUBBER	0.07	LB/MMBTU	BACT-PSD
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	01/27/2006 ACT	PULVERIZED COAL BOILER - UNIT 1	11.11	COAL	4000	T/H	Sulfur Oxides (SOx)	N		0.1	LB/MMBTU	BACT-PSD
PA-0247	BEECH HOLLOW POWER PROJECT	04/01/2005 ACT	COAL FIRED CFB	11.11	WASTE COAL			Sulfur Oxides (SOx)	A	LIMESTONE INJECTION WITH FLY ASH HYDRATION AND REINJECTION. LIMESTONE SORBENT WILL BE FED AT MAX. RATE OF APPROXIMATELY 79 TPH TO ACHIEVE CALCIUM-TO-SULFUR RATIO OF ABOUT 2.75:1 MONITORED BY CEM	0.245	LB/MMBTU	BACT-PSD
AZ-0055	NAVAJO GENERATING STATION	02/06/2012 ACT	PULVERIZED COAL FIRED BOILER	11.11	COAL	7725	MMBTU/H	Sulfur Dioxide (SO2)	A	FLUE GAS DESULFURIZATION (FGD), SCRUBBER	0		BART
AZ-0055	NAVAJO GENERATING STATION	02/06/2012 ACT	PULVERIZED COAL FIRED BOILER	11.11	COAL	7725	MMBTU/H	Sulfur Dioxide (SO2)	A	FLUE GAS DESULFURIZATION (FGD), SCRUBBER	0		BART
AZ-0055	NAVAJO GENERATING STATION	02/06/2012 ACT	PULVERIZED COAL FIRED BOILER	11.11	COAL	7725	MMBTU/H	Sulfur Dioxide (SO2)	A	FLUE GAS DESULFURIZATION (FGD), SCRUBBER	0		BART

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-5. RBLC Control Technology Determinations for Large Biomass-fired Boilers, Greater than 250 MMBtu/hr (RBLC 11.110)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
ND-0022	NORTHERN SUN	05/01/2006 ACT	WOOD/HULL FIRED BOILER	11.12	BIOMASS			Nitrogen Dioxide (NO2)	P	COMBUSTION CONTROLS	0.2	LB/MMBTU	BACT-PSD
NH-0018	BERLIN BIOPOWER	07/26/2010 ACT	EU01 BOILER #1	11.12	WOOD	1013	MMBTU/H	Nitrogen Dioxide (NO2)	A	SCR (COLD SIDE OF BAGHOUSE) WITH AMMONIA INJECTION	0.06	LB/MMBTU	BACT-PSD
WA-0335	SIMPSON TACOMA KRAFT COMPANY, LLC	05/22/2007 ACT	UTILITY AND LARGE INDUSTRIAL SIZED BOILERS/FURNACES	11.12	WOOD WASTE	595	MMBTU/H	Nitrogen Dioxide (NO2)	N	PROPER COMBUSTION CONTROLS WITH OVERFIRE AIR	0.2	LB/MMBTU	BACT-PSD
AL-0250	BOISE WHITE PAPER	03/23/2010 ACT	COMBINATION BOILER	11.12	WOOD	435	MMBTU/H	Nitrogen Oxides (NOx)	P	LOW NOX BURNERS	0.3	LB/MMBTU	BACT-PSD
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	08/30/2010 ACT	RILEY SPREADER STOKER BOILER - Transient Period (see notes)	11.12	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	A	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	102	PPM	BACT-PSD
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	08/30/2010 ACT	RILEY SPREADER STOKER BOILER	11.12	WOOD	335.7	MMBTU/H	Nitrogen Oxides (NOx)	A	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	80	PPM	BACT-PSD
FL-0301	CLEWISTON SUGAR MILL AND REFINERY	12/06/2007 ACT	BOILER 7 INDUSTRIAL SUGAR MILL BOILER FIRING BAGASSE	11.12	BAGASSE	738	MMBTU/H	Nitrogen Oxides (NOx)	P	BOILER DESIGN AND OPERATION (INCLUDES (OFA SYSTEM)	0.31	LB/MMBTU	BACT-PSD
GA-0132	YELLOW PINE ENERGY COMPANY, LLC	12/03/2008 ACT	BUBBLING FLUIDIZED BOILER	11.12	BIOMASS	1529	BTU/H HEAT INPUT	Nitrogen Oxides (NOx)	B		0.1	LB/MMBTU	BACT-PSD
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	12/17/2010 ACT	Boiler, Biomass Wood	11.12	Biomass wood	100	MW	Nitrogen Oxides (NOx)	A	Selective non-catalytic reduction system (SNCR)	0.1	LB/MMBTU	BACT-PSD
ME-0037	VERSO BUCKSPORT LLC	11/29/2010 ACT	Biomass Boiler 8	11.12	Biomass	814	MMBTU/H	Nitrogen Oxides (NOx)	A	SNCR	0.15	LB/MMBTU	BACT-PSD
MN-0074	KODA ENERGY	08/23/2007 ACT	BIOMASS BOILER 3	11.12				Nitrogen Oxides (NOx)	A	SNCR	0.25	LB/MMBTU	BACT-PSD
MN-0074	KODA ENERGY	08/23/2007 ACT	BIOMASS BOILER 4	11.12				Nitrogen Oxides (NOx)	A	SNCR	0.18	LB/MMBTU	BACT-PSD
OH-0307	SOUTH POINT BIOMASS GENERATION	04/04/2006 ACT	WOOD FIRED BOILERS (7)	11.12	WOOD	318	MMBTU/H	Nitrogen Oxides (NOx)	A	SELECTIVE CATALYTIC REDUCTION	27.98	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #1	11.12	WOOD	334	MMBTU/H	Nitrogen Oxides (NOx)	A	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	119.28	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	11.12	WOOD	334	MMBTU/H	Nitrogen Oxides (NOx)	A	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	119.28	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	11.12	WOOD	334	MMBTU/H	Nitrogen Oxides (NOx)	A	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	119.28	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURANCE #1	11.12	WOOD	334	MMBTU/H	Nitrogen Oxides (NOx)	P	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	119.28	LB/H	BACT-PSD
TX-0553	LINDALE RENEWABLE ENERGY	01/08/2010 ACT	Wood fired boiler	11.12	biomass	73	T/H	Nitrogen Oxides (NOx)	A	Selective Non-catalytic Reduction	0.15	LB/MMBTU	BACT-PSD
TX-0555	LUFKIN GENERATING PLANT	10/26/2009 ACT	Wood-fired Boiler	11.12	wood	693	MMBtu/H	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction	0.075	LB/MMBTU	BACT-PSD
VT-0037	BEAVER WOOD ENERGY FAIR HAVEN	02/10/2012 ACT	Main Boiler	11.12	wood	482	MMBTU/H	Nitrogen Oxides (NOx)	B	Good combustion control and a Multi Pollutant Catalytic Reactor (NOx SCR)	0.03	LB/MMBTU	BACT-PSD
WA-0327	SKAGIT COUNTY LUMBER MILL	01/25/2006 ACT	WOOD-FIRED COGENERATION UNIT	11.12	BARK & WASTE WOOD	430	mmBtu/H	Nitrogen Oxides (NOx)	A	SELECTIVE NONCATALYTIC REDUCTION (SNCR)	56	LB/H	BACT-PSD
WA-0329	DARRINGTON ENERGY COGENERATION POWER PLANT	02/11/2005 ACT	WOOD WASTE-FIRED BOILER	11.12	WOOD WASTE	403	MMBtTU/H	Nitrogen Oxides (NOx)	A	SNCR	0.12	LB/MMBTU	BACT-PSD
CT-0156	MONTVILLE POWER LLC	04/06/2010 ACT	42 MW Biomass utility boiler	11.12	Clean wood	600	MMBTU/H	Nitrogen Oxides (NOx)	A	Regenerative SCR	0.06	LB/MMBTU	LAER
NH-0015	CONCORD STEAM CORPORATION	02/27/2009 ACT	BOILER #1	11.12	BIOMASS	32.62	T/H	Nitrogen Oxides (NOx)	A	SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM	0.06	LB/MMBTU	LAER
NH-0016	CLEAN POWER BERLIN LLC	09/25/2009 ACT	BOILER 1	11.12	WOOD CHIPS	40.75	T/H WOOD	Nitrogen Oxides (NOx)	B	SELECTIVE CATALYTIC REDUCTION (SCR) WITH STAGED COMBUSTION	0.065	LB/MMBTU	LAER
NH-0018	BERLIN BIOPOWER	07/26/2010 ACT	EU01 BOILER #1	11.12	WOOD	1013	MMBTU/H	Nitrogen Oxides (NOx)	A	SCR (COLD SIDE OF BAGHOUSE) WITH AMMONIA INJECTION	0.06	LB/MMBRU	LAER
WA-0337	BOISE WHITE PAPER LLC	02/01/2006 ACT	UTILITY-AND LARGE INDUSTRIAL-SIZE BOILERS/FURNACES (>250 MILLION BTU/H)	11.12	WOOD/BARK	343	MMBTU/H	Nitrogen Oxides (NOx)	P	OVERFIRE AIR SYSTEM ADDED TO IMPROVE BOILER COMBUSTION SYSTEM. BOILER HAS AN ESP.	0.3	LB/MMBTU	Other Case-by-Case
MN-0074	KODA ENERGY	08/23/2007 ACT	BIOMASS BOILER 1	11.12	NATURAL GAS	308	MMBTU/H	Particulate Matter (PM)	A	CYCLONE AND ESP	0.03	LB/MMBTU	BACT-PSD
MN-0074	KODA ENERGY	08/23/2007 ACT	BIOMASS BOILER 2	11.12				Particulate Matter (PM)	A	GOOD COMBUSTION PRACTICES	0.01	LB/MMBTU	BACT-PSD
MN-0074	KODA ENERGY	08/23/2007 ACT	BIOMASS BOILER 3	11.12				Particulate Matter (PM)	A	CYCLONE AND ESP	0.037	LB/MMBTU	BACT-PSD
ND-0022	NORTHERN SUN	05/01/2006 ACT	WOOD/HULL FIRED BOILER	11.12	BIOMASS			Particulate Matter (PM)	A	ESP	0.08	LB/MMBTU	BACT-PSD
SC-0117	SPRINGS GLOBAL US, INC. - GRACE COMPLEX	11/06/2010 ACT	UTILITY- AND LARGE INDUSTRIAL-SIZE BOILERS/FURNACES	11.12	WOOD BIOMASS	260	MMBTU/H	Particulate Matter (PM)	A	MULTICLONE (80%); ESP (92%)	0.059	LB/MMBTU	BACT-PSD
VA-0298	INTERNATIONAL BIOFUELS, INC	12/13/2005 ACT	HEAT ENERGY SYSTEMS FOR PELLET PROCESSING	11.12	WOOD/WOODPASTE	77	MMBTU/H	Particulate Matter (PM)	B	SETTING CHAMBERS AND CYCLONES	6.9	LB/H	BACT-PSD
VA-0298	INTERNATIONAL BIOFUELS, INC	12/13/2005 ACT	WOOD THERMAL OXIDERS FOR WOOD PELLENT PROCESS	11.12	WOOD/WOOD PASTE	43	MMBTU/H	Particulate Matter (PM)	B	SETTING CHAMBER AND CYCLONE	3.9	LB/H	BACT-PSD
NH-0018	BERLIN BIOPOWER	07/26/2010 ACT	EU01 BOILER #1	11.12	WOOD	1013	MMBTU/H	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.01	LB/MMBTU	BACT-PSD
TX-0553	LINDALE RENEWABLE ENERGY	01/08/2010 ACT	Wood fired boiler	11.12	biomass	73	T/H	Particulate matter, filterable (FPM)	B	Good combustion practices and use of an electrostatic precipitator	0.02	LB/MMBTU	BACT-PSD
TX-0555	LUFKIN GENERATING PLANT	10/26/2009 ACT	Wood-fired Boiler	11.12	wood	693	MMBtu/H	Particulate matter, filterable (FPM)	A	Electrostatic Precipitator	0.012	LB/MMBTU	BACT-PSD
GA-0132	YELLOW PINE ENERGY COMPANY, LLC	12/03/2008 ACT	BUBBLING FLUIDIZED BOILER	11.12	BIOMASS	1529	BTU/H HEAT INPUT	Particulate matter, filterable < 10 µ (FPM10)	B		0.01	LB/MMBTU	BACT-PSD
GA-0140	MITCHELL STEAM-GENERATING PLANT (PLANT MITCHELL)	12/03/2010 ACT	Boiler, Wood-Fired	11.12	Wood, Biomass	96	MW	Particulate matter, filterable < 10 µ (FPM10)	A	High Frequency Power Supply (field #1, #2), Multiclone Mechanical Collector System	0.04	LB/MMBTU	BACT-PSD
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	12/17/2010 ACT	Boiler, Biomass Wood	11.12	Biomass wood	100	MW	Particulate matter, filterable < 10 µ (FPM10)	A	Fabric filter baghouse and dust sorbent injection system.	0.01	LB/MMBTU	BACT-PSD
MN-0074	KODA ENERGY	08/23/2007 ACT	BIOMASS BOILER 4	11.12				Particulate matter, filterable < 10 µ (FPM10)	A	GOOD COMBUSTION PRACTICE	0.01	LB/MMBTU	BACT-PSD
NH-0018	BERLIN BIOPOWER	07/26/2010 ACT	EU01 BOILER #1	11.12	WOOD	1013	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.01	LB/MMBTU	BACT-PSD
OH-0307	SOUTH POINT BIOMASS GENERATION	04/04/2006 ACT	WOOD FIRED BOILERS (7)	11.12	WOOD	318	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	PULSE JET BAGHOUSE	3.97	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #1	11.12	WOOD	334	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	WET ELECTROSTATIC PRECIPITATORS.	58.99	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	11.12	WOOD	334	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	SOURCES VENT TO A COMMON STACK WITH THE CONTROLS ADDED ON THAT STACK.	58.99	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	11.12	WOOD	334	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	WET ELECTROSTATIC PRECIPITATORS	58.99	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURANCE #1	11.12	WOOD	334	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	WET ELECTROSTATIC PRECIPITATORS	58.99	LB/H	BACT-PSD
VT-0037	BEAVER WOOD ENERGY FAIR HAVEN	02/10/2012 ACT	Main Boiler	11.12	wood	482	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	Multi-cyclones and ESP	0.012	LB/MMBTU	BACT-PSD
WA-0327	SKAGIT COUNTY LUMBER MILL	01/25/2006 ACT	WOOD-FIRED COGENERATION UNIT	11.12	BARK & WASTE WOOD	430	mmBtu/H	Particulate matter, filterable < 10 µ (FPM10)	A	ELECTROSTATIC PRECIPITATOR	0.02	LB/MMBTU	BACT-PSD
WA-0329	DARRINGTON ENERGY COGENERATION POWER PLANT	02/11/2005 ACT	WOOD WASTE-FIRED BOILER	11.12	WOOD WASTE	403	MMBtTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	DRY ESP	0.02	LB/MMBTU	BACT-PSD
WA-0335	SIMPSON TACOMA KRAFT COMPANY, LLC	05/22/2007 ACT	UTILITY AND LARGE INDUSTRIAL SIZED BOILERS/FURNACES	11.12	WOOD WASTE	595	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	EXISTING ELECTROSTATIC PRECIPITATOR	0.02	LB/MMBTU	BACT-PSD
WA-0336	GRAYS HARBOR PAPER LP	11/17/2006 ACT	UTILITY-AND LARGE INDUSTRIAL SIZED BOILERS	11.12	WOOD WASTE	379	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	1. MULTICLONES WITH 80 14" DIAMETER TUBES. 2. TWO PARALLEL IMPRINGEMENT WET SCRUBBER WITH 6 TOP AND 6 BOTTOM SHOWERS	52.5	LB/H	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	12/17/2010 ACT	Boiler, Biomass Wood	11.12	Biomass wood	100	MW	Particulate matter, filterable < 2.5 µ (FPM2.5)	A	Fabric filter baghouse and dust sorbent injection system.	0.018	LB/MMBTU	BACT-PSD
NH-0018	BERLIN BIOPOWER	07/26/2010 ACT	EU01 BOILER #1	11.12	WOOD	1013	MMBTU/H	Particulate matter, filterable < 2.5 µ (FPM2.5)	A	BAGHOUSE	0.01	LB/MMBTU	BACT-PSD
SC-0117	SPRINGS GLOBAL US, INC. - GRACE COMPLEX	11/06/2010 ACT	UTILITY- AND LARGE INDUSTRIAL-SIZE BOILERS/FURNACES	11.12	WOOD BIOMASS	260	MMBTU/H	Particulate matter, filterable < 2.5 µ (FPM2.5)	A	MULTICLONE (80%); ESP (92%)	0.043	LB/MMBTU	BACT-PSD
CA-1203	SIERRA PACIFIC INDUSTRIES-LOYALTON	08/30/2010 ACT	RILEY SPREADER STOKER BOILER	11.12	WOOD	335.7	MMBTU/H	Particulate matter, total (TPM)	A	MULTICLONES AND ELECTROSTATIC PRECIPITATOR (ESP)	20	% OPACITY	BACT-PSD
CT-0156	MONTVILLE POWER LLC	04/06/2010 ACT	42 MW Biomass utility boiler	11.12	Clean wood	600	MMBTU/H	Particulate matter, total (TPM)	A	Dry ESP	0.026	LB/MMBTU	BACT-PSD
ME-0037	VERSO BUCKSPORT LLC	11/29/2010 ACT	Biomass Boiler 8	11.12	Biomass	814	MMBTU/H	Particulate matter, total (TPM)	A	existing multiclone and ESP	0.03	LB/MMBTU	BACT-PSD
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #1	11.12	WOOD	334	MMBTU/H	Particulate matter, total (TPM)	A	WET ELECTROSTATIC PRECIPITATORS	58.99	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	11.12	WOOD	334	MMBTU/H	Particulate matter, total (TPM)	A	WET ELECTROSTATIC PRECIPITATORS	58.99	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	11.12	WOOD	334	MMBTU/H	Particulate matter, total (TPM)	A	WET ELECTROSTATIC PRECIPITATORS	58.99	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURANCE #1	11.12	WOOD	334	MMBTU/H	Particulate matter, total (TPM)	A	WET ELECTROSTATIC PRECIPITATORS	58.99	LB/H	BACT-PSD
TX-0555	LUFKIN GENERATING PLANT	10/26/2009 ACT	Wood-fired Boiler	11.12	wood	693	MMBtu/H	Particulate matter, total (TPM)	A	Electrostatic Precipitator	0.025	LB/MMBTU	BACT-PSD
VT-0037	BEAVER WOOD ENERGY FAIR HAVEN	02/10/2012 ACT	Main Boiler	11.12	wood	482	MMBTU/H	Particulate matter, total (TPM)	A	Multi-cyclones and ESP	0.019	LB/MMBTU	BACT-PSD
GA-0132	YELLOW PINE ENERGY COMPANY, LLC	12/03/2008 ACT	BUBBLING FLUIDIZED BOILER	11.12	BIOMASS	1529	BTU/H HEAT INPUT	Particulate matter, total < 10 µ (TPM10)	B		0.018	LB/MMBTU	BACT-PSD
MN-0078	SAPPI CLOQUET LLC	10/28/2009 ACT	BOILER	11.12	WOOD	430	MMBTU/H	Particulate matter, total < 2.5 µ (TPM2.5)	A	EXISTING MULTICLONE/ESP COMBINATION	13.5	LB/H	BACT-PSD
MN-0078	SAPPI CLOQUET LLC	10/28/2009 ACT	BOILER	11.12	WOOD	430	MMBTU/H	Particulate matter, total < 2.5 µ (TPM2.5)	A	EXISTING MULTICLONE/ESP COMBINATION	13.5	LB/H	BACT-PSD
AL-0223	STEVENSON MILL	07/14/2006 ACT	NO. 2 WOOD-FIRED BOILER	11.12	BIOMASS	620	MMBTU/H	Sulfur Dioxide (SO2)	N		93	LB/H	BACT-PSD
GA-0132	YELLOW PINE ENERGY COMPANY, LLC	12/03/2008 ACT	BUBBLING FLUIDIZED BOILER	11.12	BIOMASS	1529	BTU/H HEAT INPUT	Sulfur Dioxide (SO2)	B		0.014	LB/MMBTU	BACT-PSD
LA-0249	RED RIVER MILL	05/09/2011 ACT	NO. 2 HOGGED FUEL BOILER	11.12	HOGGED FUEL/BARK	992.43	MMBTU/H	Sulfur Dioxide (SO2)	P	USE OF LOW SULFUR FUELS	60	LB/H	BACT-PSD
ME-0037	VERSO BUCKSPORT LLC	11/29/2010 ACT	Biomass Boiler 8	11.12	Biomass	814	MMBTU/H	Sulfur Dioxide (SO2)	P	0.7% sulfur when firing oil	0.8	LB/MMBTU	BACT-PSD
ND-0022	NORTHERN SUN	05/01/2006 ACT	WOOD/HULL FIRED BOILER	11.12	BIOMASS			Sulfur Dioxide (SO2)	N		0.47	LB/MMBTU	BACT-PSD
NH-0018	BERLIN BIOPOWER	07/26/2010 ACT	EU01 BOILER #1	11.12	WOOD	1013	MMBTU/H	Sulfur Dioxide (SO2)	B	WOOD FUEL SORBENT INJECTION (AS NEEDED)	0.012	LB/MMBTU	BACT-PSD
OH-0307	SOUTH POINT BIOMASS GENERATION	04/04/2006 ACT	WOOD FIRED BOILERS (7)	11.12	WOOD	318	MMBTU/H	Sulfur Dioxide (SO2)	A	SPRAY DRYER ADSORBER OR DRY SODIUM BICARBONATE INJECTION SYSTEM	22.13	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #1	11.12	WOOD	334	MMBTU/H	Sulfur Dioxide (SO2)	P	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	11.12	WOOD	334	MMBTU/H	Sulfur Dioxide (SO2)	P	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	11.12	WOOD	334	MMBTU/H	Sulfur Dioxide (SO2)	P	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURANCE #1	11.12	WOOD	334	MMBTU/H	Sulfur Dioxide (SO2)	P	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	BACT-PSD
TX-0553	LINDALE RENEWABLE ENERGY	01/08/2010 ACT	Wood fired boiler	11.12	biomass	73	T/H	Sulfur Dioxide (SO2)	N		0.025	LB/MMBTU	BACT-PSD
TX-0555	LUFKIN GENERATING PLANT	10/26/2009 ACT	Wood-fired Boiler	11.12	wood	693	MMBtu/H	Sulfur Dioxide (SO2)	N		0.025	LB/MMBTU	BACT-PSD
VT-0037	BEAVER WOOD ENERGY FAIR HAVEN	02/10/2012 ACT	Main Boiler	11.12	wood	482	MMBTU/H	Sulfur Dioxide (SO2)	P	Use of low sulfur fuel (wood)	0.02	LB/MMBTU	BACT-PSD
WA-0327	SKAGIT COUNTY LUMBER MILL	01/25/2006 ACT	WOOD-FIRED COGENERATION UNIT	11.12	BARK & WASTE WOOD	430	mmBtu/H	Sulfur Dioxide (SO2)	N		0.025	LB/MMBTU	BACT-PSD
CT-0156	MONTVILLE POWER LLC	04/06/2010 ACT	42 MW Biomass utility boiler	11.12	Clean wood	600	MMBTU/H	Sulfur Oxides (SOx)	N	Low sulfur fuels	0.025	LB/MMBTU	BACT-PSD
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	12/17/2010 ACT	Boiler, Biomass Wood	11.12	Biomass wood	100	MW	Sulfur Oxides (SOx)	A	Dust sorbent injection system	0.01	LB/MMBTU	BACT-PSD

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-6. Summary of Identified NO_X Control Technology - Mid-sized Boilers, 100 to 250 MMBtu/hr

Pollutant	Control Technology Used	Number of Diesel-fired (RBLC ID 12.220) Entries (1 Total)	Number of Gas-fired (RBLC ID 12.310) Entries (32 Total)
NO_X	SCR	-	4
	Low NOX Burner	-	12
	Flue Gas Recirculation	-	2
	Staged Combustion	-	1
	None	1	9
	Good Combustion Practice	-	4

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-7. Summary of Identified PM Control Technology - Mid-sized Boilers, 100 to 250 MMBtu/hr

Pollutant	Control Technology Used	Number of Diesel-fired (RBLC ID 12.220) Entries (1 Total)	Number of Gas-fired (RBLC ID 12.310) Entries (25 Total)
PM	None	1	6
	Good Combustion Practice	-	14
	Use of Natural Gas	-	5

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-8. Summary of Identified SO_2 Control Technology - Mid-sized Boilers, 100 to 250 MMBtu/hr

Pollutant	Control Technology Used	Number of Diesel-fired (RBLC ID 12.220) Entries (1 Total)	Number of Gas-fired (RBLC ID 12.310) Entries (8 Total)
SO_2	Natural Gas	-	3
	None	1	5

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-9. RBLC Control Technology Determinations for Mid-sized Diesel-fired Boilers, 100 to 250 MMBtu/hr (RBLC 12.220)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
OH-0336	CAMPBELL SOUP COMPANY	12/14/2010 ACT	Bolier (3)	12.22	Number 2 fuel oil	3246593	GAL/YR	Nitrogen Oxides (NOx)	N		0.1	LB/MMBTU	OTHER CASE-BY-CASE
OH-0336	CAMPBELL SOUP COMPANY	12/14/2010 ACT	Bolier (3)	12.22	Number 2 fuel oil	3246593	GAL/YR	Particulate matter, total < 10 µ (TPM10)	N		0.02	LB/MMBTU	OTHER CASE-BY-CASE
OH-0336	CAMPBELL SOUP COMPANY	12/14/2010 ACT	Bolier (3)	12.22	Number 2 fuel oil	3246593	GAL/YR	Sulfur Dioxide (SO2)	N		0.35	T/YR	OTHER CASE-BY-CASE

Table A-10. RBLC Control Technology Determinations for Mid-sized Gas-fired Boilers, 100 to 250 MMBtu/hr (RBLC 12.310)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
AK-0071	INTERNATIONAL STATION POWER PLANT	12/20/2010 ACT	Duct Burners (4)	12.31	140	MMBTU/H	Nitrogen Oxides (NOx)	A	Selective Catalytic Reduction	5	PPMDV	BACT-PSD
AK-0073	INTERNATIONAL STATION POWER PLANT	12/20/2010 ACT	Fuel Combustion	12.31	140	MMBTU/H	Nitrogen Oxides (NOx)	A	Duct Burners EU IDs 9 through 12 shall be equipped with Selective Catalytic Reduction (SCR). SCR is a post-combustion gas treatment technique for reduction of nitric oxide (NO) and nitrogen dioxide (NO2) in the turbine exhaust stream to molecular nitrogen, water, and oxygen. This process is accomplished by using ammonia (NH3) as a reducing agent, and is injected into the flue gas upstream of the catalyst bed. By lowering the activation energy of the NOx decomposition removal efficiency of 80 to 90 percent are achievable.	5	PPM	BACT-PSD
AK-0073	INTERNATIONAL STATION POWER PLANT	12/20/2010 ACT	Fuel Combustion	12.31	12.5	MMBTU/H	Nitrogen Oxides (NOx)	A	Auxiliary heater EU 15 shall be equipped with Low NOx Burner/Flue Gas Recirculation (LNB/FGR) designs. LNBs utilize staged combustion to minimize thermal NOx formation by providing a fuel-rich reducing atmosphere in which molecular nitrogen is preferentially formed rather than NOx. FGR involves recycling a portion of the combustion gasses from the stack to the boiler windbox. The low oxygen combustion products, when mixed with combustion air, lower the overall excess oxygen concentration and act as a heat sink to lower the peak flame temperature with results in limiting thermal NOx formation.	32	LB/MMSCF	BACT-PSD
CA-1146	CELITE	06/11/2007 ACT	HEATER-OTHER PROCESS	12.31	35	35 MMBTU/H	Nitrogen Oxides (NOx)	A	LOW-NOX BURNER	20	PPMVD @ 3% O2	BACT-PSD
CA-1147	CELITE	06/11/2007 ACT	HEATER-OTHER PROCESS	12.31	48	48 MMBTU/H	Nitrogen Oxides (NOx)	A	LOW-NOX BURNER	20	PPMVD @ 3% O2	BACT-PSD
CA-1148	CELITE	06/11/2007 ACT	HEATER-OTHER PROCESS	12.31	50	50 MMBTU/H	Nitrogen Oxides (NOx)	A	LOW-NOX BURNER	73	PPMVD @ 3% O2	BACT-PSD
CA-1206	STOCKTON COGEN COMPANY	09/16/2011 ACT	AUXILIARY BOILER	12.31	178	MMBTU/H	Nitrogen Oxides (NOx)	N		7	PPMVD	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	AUXILIARY BOILER	12.31	110	MMBTU/H	Nitrogen Oxides (NOx)	N		9	PPMVD	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Startup Heater	12.31	110.12	MMBTU/H	Nitrogen Oxides (NOx)	P	good combustion practices	0.119	LB/MMBTU	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	MBTU/H PACKAGE BOILER, S	12.31	250	MMBTU/H	Nitrogen Oxides (NOx)	B	LOW-NOX BURNER AND FGR	0.02	LB/MMBTU	BACT-PSD
LA-0229	SHINTECH PLAQUEMINE PLANT 2	07/10/2008 ACT	QT113 - TWO UTIL. BOILERS (	12.31	250	MMBTU/H	Nitrogen Oxides (NOx)	B	LOW NOX BURNERS (LNB) IN COMBINATION WITH SELECTIVE CATALYTIC REDUCTION (SCR)	0.01	LB/MMBTU	BACT-PSD
LA-0244	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	11/29/2010 ACT	EQT0029 - Hot Oil Heater H-601	12.31	170	MMBTU/H	Nitrogen Oxides (NOx)	P	low nox burners	19.69	LB/H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009 ACT	AUXILARY BOILER	12.31	220	MMBTU/H	Nitrogen Oxides (NOx)	P	LOW NOX BURNER	0.018	LB/MMBTU	BACT-PSD
MN-0062	HEARTLAND CORN PRODUCTS	12/22/2005 ACT	BOILER	12.31	198	MMBTU/H	Nitrogen Oxides (NOx)	N		0.04	LB/MMBTU	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/2005 ACT	AUXILLIARY BOILER	12.31	110.2	MMBTU/H	Nitrogen Oxides (NOx)	P	LOW-NOX BURNERS, GOOD COMBUSTION CONTROL AND CLEAN BURNING, LOW-SULFUR FUEL (NATURAL GAS).	15.13	LB/H	BACT-PSD
NV-0043	LASCO BATHWARE	10/25/2006 ACT	. BURNING FOR THERMOSET	12.31	6.3	MMBTU/H	Nitrogen Oxides (NOx)	N	N/A	0.96	LB/H	BACT-PSD
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	BOILER - UNIT PA15	12.31	21	MMBTU/H	Nitrogen Oxides (NOx)	P	LOW NOX BURNER	0.0366	LB/MMBTU	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/08/2009 ACT	AUXILIARY BOILER	12.31	150	MMBTU/H	Nitrogen Oxides (NOx)	N		21	LB/H	BACT-PSD
OR-0046	TURNER ENERGY CENTER, LLC	01/06/2005 ACT	AUXILIARY BOILER	12.31	417904	MMBTU/YR	Nitrogen Oxides (NOx)	A	SELECTIVE CATALYTIC REDUCTION	0.011	LB/MMBTU	BACT-PSD
TX-0499	SANDY CREEK ENERGY STATION	07/24/2006 ACT	AUXILLARY BOILER	12.31	175	MMBTU/H	Nitrogen Oxides (NOx)	N		1.8	LB/H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Startup Heater	12.31	110.12	MMBTU/H	Nitrous Oxide (N2O)	P	good combustion practices	0.0006	LB/MMBTU	BACT-PSD
MN-0076	BLANDIN PAPER/RAPIDS ENERGY CENTER	09/18/2008 ACT	BOILER	12.31	280	MMBTU/H	Nitrogen Oxides (NOx)		FLUE GAS RECIRCULATION WITH LOW-NOX BURNERS	0.035	LB/MMBTU	Other Case-by-Case
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILERS - UNITS CC026, CC027 AND CC028 AT CITY CENTER	12.31	44	MMBTU/H	Nitrogen Oxides (NOx)		LOW NOX BURNER AND GOOD COMBUSTION PRACTICES	0.0109	LB/MMBTU	Other Case-by-Case
OH-0336	CAMPBELL SOUP COMPANY	12/14/2010 ACT	Boilers (3)	12.31	0		Nitrogen Oxides (NOx)			0.04	LB/MMBTU	OTHER CASE-BY-CASE
PA-0267	CRAFTMASTER MFG INC	07/29/2008 ACT	RTO 2	12.31	12300	CF/H	Nitrogen Oxides (NOx)			85	PPMVD	Other Case-by-Case
PA-0267	CRAFTMASTER MFG INC	07/29/2008 ACT	RTO 1	12.31	10.7	MMBTU/H	Nitrogen Oxides (NOx)		IT IS A CONTROL DEVISE	85	PPMDV	Other Case-by-Case
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	MBTU/H PACKAGE BOILER, S	12.31	250	MMBTU/H	Particulate Matter (PM)	P	GOOD COMBUSTION PRACTICES	0.0052	LB/MMBTU	BACT-PSD
TX-0499	SANDY CREEK ENERGY STATION	07/24/2006 ACT	AUXILLARY BOILER	12.31	175	MMBTU/H	Particulate Matter (PM)	N		0.88	LB/H	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	MBTU/H PACKAGE BOILER, S	12.31	250	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION PRACTICES	0.0052	LB/MMBTU	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/2005 ACT	AUXILLIARY BOILER	12.31	110.2	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	N	LOW-NOX BURNERS, GOOD COMBUSTION CONTROL AND CLEAN BURNING, LOW-SULFUR FUEL (NATURAL GAS).	0.82	LB/H	BACT-PSD
NV-0043	LASCO BATHWARE	10/25/2006 ACT	. BURNING FOR THERMOSET	12.31	6.3	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	N	N/A	0.03	LB/H	BACT-PSD
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	BOILER - UNIT PA15	12.31	21	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	P	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0076	LB/MMBTU	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/08/2009 ACT	AUXILIARY BOILER	12.31	150	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	N		1.14	LB/H	BACT-PSD
OR-0046	TURNER ENERGY CENTER, LLC	01/06/2005 ACT	AUXILIARY BOILER	12.31	417904	MMBTU/YR	Particulate matter, filterable < 10 µ (FPM10)	N	USE OF NATURAL GAS	0		BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	12/20/2010 ACT	Duct Burners (4)	12.31	140	MMBTU/H	Particulate matter, total (TPM)	P	Good Combustion Practices	7.6	LB/MMSCF	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	AUXILIARY BOILER	12.31	110	MMBTU/H	Particulate matter, total (TPM)	P	USE PUC QUALITY NATURAL GAS	0.8	LB/H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Startup Heater	12.31	110.12	MMBTU/H	Particulate matter, total (TPM)	P	good combustion practices	0.0024	LB/MMBTU	BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	12/20/2010 ACT	Duct Burners (4)	12.31	140	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	P	Good Combustion Practices	7.6	LB/MMSCF	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
AK-0073	INTERNATIONAL STATION POWER PLANT	12/20/2010 ACT	Fuel Combustion	12.31	140	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	P	Combustion Turbines EU IDs 9-12 use good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	7.6	LB/MMBTU	BACT-PSD
AK-0073	INTERNATIONAL STATION POWER PLANT	12/20/2010 ACT	Fuel Combustion	12.31	12.5	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	P	Combustion Turbines EU ID# 15 uses good combustion practices involve increasing the residence time and excess oxygen to ensure complete combustion which in turn minimize particulates without an add-on control technology.	7.6	LB/MMBTU	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	AUXILIARY BOILER	12.31	110	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	P	USE PUC QUALITY NATURAL GAS	0.8	LB/H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Startup Heater	12.31	110.12	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	P	good combustion practices	0.0024	LB/MMBTU	BACT-PSD
LA-0229	SHINTECH PLAQUEMINE PLANT 2	07/10/2008 ACT	QT113 - TWO UTIL. BOILERS (	12.31	250	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	P	GOOD COMBUSTION PRACTICES AND CLEAN BURNING FUELS	0.005	LB/MMBTU	BACT-PSD
LA-0244	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	11/29/2010 ACT	EQT0029 - Hot Oil Heater H-601	12.31	170	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	N	No additional control	1.71	LB/H	BACT-PSD
MA-0037	CENTRAL HEATING PLANT: AMHERST CAMPUS	10/29/2008 ACT	BOILERS	12.31	162	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	N		0.02	LB/MMBTU	BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	12/20/2010 ACT	Duct Burners (4)	12.31	140	MMBTU/H	Particulate matter, total < 2.5 µ (TPM2.5)	P	Good Combustion Practices	7.6	LB/MMSCF	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	AUXILIARY BOILER	12.31	110	MMBTU/H	Particulate matter, total < 2.5 µ (TPM2.5)	P	USE PUC QUALITY NATURAL GAS	0.8	LB/H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Startup Heater	12.31	110.12	MMBTU/H	Particulate matter, total < 2.5 µ (TPM2.5)	P	good combustion practices	0.0024	LB/MMBTU	BACT-PSD
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILERS - UNITS CC026, CC027 AND CC028 AT CITY CENTER	12.31	44	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)		LIMITING THE FUEL TO NATURAL GAS ONLY AND GOOD COMBUSTION PRACTICES	0.0075	LB/MMBTU	LAER
OH-0336	CAMPBELL SOUP COMPANY	12/14/2010 ACT	Boilers (3)	12.31	0		Particulate matter, total < 10 µ (TPM10)			0.01	LB/MMBTU	OTHER CASE-BY-CASE
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/2007 ACT	IEALING FURNACE (LA43) (MU	12.31	196.4	MMBTU/H	Sulfur Dioxide (SO2)	N		0.0006	LB/MMBTU	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/08/2009 ACT	AUXILIARY BOILER	12.31	150	MMBTU/H	Sulfur Dioxide (SO2)	N		0.09	LB/H	BACT-PSD
TX-0499	SANDY CREEK ENERGY STATION	07/24/2006 ACT	AUXILLARY BOILER	12.31	175	MMBTU/H	Sulfur Dioxide (SO2)	N		0.11	LB/H	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/2005 ACT	AUXILLIARY BOILER	12.31	110.2	MMBTU/H	Sulfur Oxides (SOx)	P	LOW-NOX BURNERS, GOOD COMBUSTION CONTROL AND CLEAN BURNING, LOW-SULFUR FUEL (NATURAL GAS).	0.61	LB/H	BACT-PSD
NV-0050	MGM MIRAGE	11/30/2009 ACT	S CC026, CC027 AND CC028 A	12.31	44	MMBTU/H	Sulfur Oxides (SOx)	P	LIMITING THE FUEL TO NATURAL GAS ONLY	0.0007	LB/MMBTU	BACT-PSD
PA-0255	ELLWOOD QUALITY STEELS COMPANY	08/01/2007 ACT	ELECTRIC ARC FURNACE	12.31	30	MCF/H	Sulfur Oxides (SOx)	N		0.45	LB/H	BACT-PSD
MN-0076	BLANDIN PAPER/RAPIDS ENERGY CENTER	09/18/2008 ACT	BOILER	12.31	280	MMBTU/H	Sulfur Dioxide (SO2)		NATURAL GAS ONLY	0		Other Case-by-Case
OH-0336	CAMPBELL SOUP COMPANY	12/14/2010 ACT	Boilers (3)	12.31	0		Sulfur Dioxide (SO2)			0.0006	LB/MMBTU	OTHER CASE-BY-CASE

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-11. Summary of Identified NO_X Control Technology - Small Diesel-fired Boiler (RBLC 13.220)

Pollutant	Control Technology Used	Number of RBLC Entries (15 Total)
NO_X	LNB/FGR	5
	Good Combustion Practice	2
	None	6

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-12. Summary of Identified PM Control Technology - Small Diesel-fired Boiler (RBLC 13.220)

Pollutant	Control Technology Used	Number of RBLC Entries (8 Total)
$PM_{2.5}$	None	3
	Good Combustion Practice	4
	Scrubber	1

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-13. Summary of Identified SO_2 Control Technology - Small Diesel-fired Boiler (RBLC 13.220)

Pollutant	Control Technology Used	Number of RBLC Entries (2 Total)
SO_2	ULSD	5
	None	1
	Good Combustion Practice	1

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-14. RBLC Control Technology Determinations for Small Diesel-fired Boiler, < 100 MMBtu/hr (RBLC 13.220)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS	Other Applicable Requirements
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	OILERS/HEATERS - DIESEL OIL-FIRE	13.22	DIESEL OIL			Nitrogen Oxides (NOx)	P	LOW-NOX BURNER	0.14	LB/MMBTU	BACT-PSD	SIP , OPERATING PERMIT
NV-0050	MGM MIRAGE	11/30/2009 ACT	ENERATORS - UNITS CC009 THRU	13.22	DIESEL OIL	3622	HP	Nitrogen Oxides (NOx)	P	TURBOCHARGER AAND AFTER-COOLER	0.01	LB/HP-H	Other Case-by-Case	SIP , OPERATING PERMIT
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/2006 ACT	AUXILIARY BOILER	13.22	DISTILLATE OIL	28	MMBTU/H	Nitrogen Oxides (NOx)	A	LOW NOX BURNERS & FLUE GAS RECIRCULATION	0.1	LB/MMBTU	BACT-PSD	OPERATING PERMIT
VA-0299	UNITED STATES GYPSUM COMPANY	06/19/2006 ACT	BOILER, MIXER HOT WATER	13.22		2.6	MMBTU/H	Nitrogen Oxides (NOx)	N		0.3	LB/H	BACT-PSD	OPERATING PERMIT
VA-0307	HERCULES INC	10/05/2007 ACT	CHEMICAL PREP	13.22	DISTILLATE OIL	90	MMBTU	Nitrogen Oxides (NOx)	B	NOX PORT OR EQUIVALENT LOW NOX BURNER AND GOOD COMBUSTION PRACTICES	0.143	LB/MMBTU	BACT-PSD	NSPS , OPERATING PERMIT
VA-0307	HERCULES INC	10/05/2007 ACT	CHEMICAL PREP	13.22	DISTILLATE OIL	90	MMBTU	Nitrogen Oxides (NOx)	B	LOW NOX BURNER AND GOOD COMBUSTION PRACTICES	0.143	LB/MMBTU	BACT-PSD	NSPS , OPERATING PERMIT
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	05/03/2007 ACT	BOILER (2), NO. 2 FUEL OIL	13.22	FUEL OIL #2	20.4	MMBTU/H	Nitrogen Oxides (NOx)	P	LOW NOX BURNERS AND FLUE GAS RECIRCULATION	1.5	LB/H	LAER	
MD-0037	MEDIMMUNE FREDERICK CAMPUS	01/28/2008 ACT	FOUR (4) DIESEL FIRED (BACK-UP FUEL) BOILERS EACH RATED AT 29.4 MILLION BTU PER HOUR.	13.22	DIESEL (NO. 2 FUEL OIL)	29.4	MMBTU/H	Nitrogen Oxides (NOx)	N		58	PPM	OTHER CASE-BY-CASE	
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	05/03/2007 ACT	BOILER (2), NO. 2 FUEL OIL	13.22	FUEL OIL #2	20.4	MMBTU/H	Particulate Matter (PM)	N		0.31	LB/H	BACT-PSD	NSPS , MACT , SIP
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/2006 ACT	AUXILIARY BOILER	13.22	DISTILLATE OIL	28	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	P	LOW SULFUR FUEL (0.04%).	0.015	LB/MMBTU	BACT-PSD	OPERATING PERMIT
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	05/03/2007 ACT	BOILER (2), NO. 2 FUEL OIL	13.22	FUEL OIL #2	20.4	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	N		0.5	LB/H	BACT-PSD	SIP , NSPS , MACT
VA-0307	HERCULES INC	10/05/2007 ACT	CHEMICAL PREP	13.22	DISTILLATE OIL	90	MMBTU	Particulate matter, filterable < 10 µ (FPM10)	B	WET OR DRY SCRUBBER AND GOOD COMBUSTION PRACTICES	1.5	LB/H	BACT-PSD	NSPS , OPERATING PERMIT
VA-0307	HERCULES INC	10/05/2007 ACT	CHEMICAL PREP	13.22	DISTILLATE OIL	90	MMBTU	Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION PRACTICES	0.03	LB/H	BACT-PSD	NSPS , OPERATING PERMIT
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	BOILERS/HEATERS - DIESEL OIL-FIRED	13.22	DIESEL OIL			Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION PRACTICE	0.019	LB/MMBTU	Other Case-by-Case	
AK-0081	POINT THOMSON PRODUCTION FACILITY	06/12/2013 ACT	Combustion	13.22	ULSD	0		Particulate matter, total < 2.5 µ (TPM2.5)	P	Good combustion and operation practices	0.25	LB/GAL	OTHER CASE-BY-CASE	
GA-0132	YELLOW PINE ENERGY COMPANY, LLC	12/03/2008 ACT	AUXILIARY BOILER	13.22	LOW SULFUR	0		Sulfur Dioxide (SO2)	P	FUEL SULFUR CONTENG OF DISTILLATE FUEL OF 0.05 WEIGHT WHICH IS REDUCED TO 15 PPM BY 2010: LIMITED OPERATION AND GOOD COMBUSTION CONTROLS.	250	MMBTU/H	BACT-PSD	MACT , OPERATING PERMIT
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	OILERS/HEATERS - DIESEL OIL-FIRE	13.22	DIESEL OIL			Sulfur Dioxide (SO2)	P	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.05% BY WEIGHT	0.0094	LB/MMBTU	BACT-PSD	SIP , OPERATING PERMIT
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/2006 ACT	AUXILIARY BOILER	13.22	DISTILLATE OIL	28	MMBTU/H	Sulfur Dioxide (SO2)	P	LOW SULFUR FUEL (0.04%).	0.041	LB/MMBTU	BACT-PSD	NSPS , OPERATING PERMIT
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	05/03/2007 ACT	BOILER (2), NO. 2 FUEL OIL	13.22	FUEL OIL #2	20.4	MMBTU/H	Sulfur Dioxide (SO2)	N		10.4	LB/H	BACT-PSD	NSPS , SIP
VA-0307	HERCULES INC	10/05/2007 ACT	CHEMICAL PREP	13.22	DISTILLATE OIL	90	MMBTU	Sulfur Dioxide (SO2)	B	WET OR DRY SCRUBBER AND GOOD COMBUSTION PRACTICES	9.1	LB/H	BACT-PSD	NSPS , OPERATING PERMIT
VA-0307	HERCULES INC	10/05/2007 ACT	CHEMICAL PREP	13.22	DISTILLATE OIL	90	MMBTU	Sulfur Dioxide (SO2)	P	.5% S FUEL AND GOOD COMBUSTION PRACTICES	45.4	LB/H	BACT-PSD	NSPS , OPERATING PERMIT
NV-0050	MGM MIRAGE	11/30/2009 ACT	ENERATORS - UNITS CC009 THRU	13.22	DIESEL OIL	3622	HP	Sulfur Oxides (SOx)	P	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.03% BY WEIGHT.	0.0002	LB/HP-H	BACT-PSD	SIP , OPERATING PERMIT

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015

Table A-15. Summary of Identified NO_X Control Technology - Large Diesel Engines > 500 hp (RBLC 17.110)

Pollutant	Control Technology Used	Number of RBLC Entries (66 Total)
NO_X	Good Combustion Practice	16
	None	13
	Limited Operation	7
	NSPS Subpart IIII Standards	7
	Turbocharger & Aftercooler	7
	Ignition Timing Retard	5
	Non Road Engine Standards (Tiers I - IV)	5
	Fuel Injection Timing Retard	3
	SCR	1
	Reduce NOX 90%	1
	EPA Cert.	1

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-16. Summary of Identified $PM_{2.5}$ Control Technology - Large Diesel Engines > 500 hp (RBLC 17.110)

Pollutant	Control Technology Used	Number of RBLC Entries (86 Total)
PM	Good Combustion Practice	29
	None	35
	NSPS Subpart IIII	8
	Limited Operation	5
	Non Road Engine Standards (Tiers I - IV)	5
	Low Ash Diesel	3
	Positive Crankcase Ventilation	1

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-17. Summary of Identified SO_2 Control Technology - Large Diesel Engines > 500 hp (RBLC 17.110)

Pollutant	Control Technology Used	Number of RBLC Entries (35 Total)
SO_2	Limit Sulfur in Fuel	13
	Good Combustion Practice	5
	Ultra Low Sulfur Diesel	5
	Limited Operation	5
	NSPS Subpart IIII Standards	4
	None	3

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-18. RBLC Control Technology Determinations for Large Diesel-fired Engines Greater than 500 hp (RBLC 17.110)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
OK-0118	HUGO GENERATING STA	02/09/2007 ACT	EMERGENCY DIESEL INTERNAL COMBUSTION ENGINES	17.11				Nitrogen Dioxide (NO2)	P	USE OF LOW SULFUR NO.2 FUEL OIL COMBINED WITH GOOD COMBUSTION PRACTICES AND LIMITED ANNUAL OPERATION	0		BACT-PSD
AK-0064	DUTCH HARBOR POWER PLANT	01/31/2007 ACT	I.C.	17.11	FUEL OIL	5000	KW	Nitrogen Oxides (NOx)	A	REDUCE NOX BY 90%	1.36	G/KW-H	BACT-PSD
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/2005 ACT	FIRE WATER PUMPS NOS 1 AND 2	17.11	NO. 2 DIESEL FUEL	5.46	MMBTU/H	Nitrogen Oxides (NOx)	N		4	G/KW-H	BACT-PSD
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/2005 ACT	EMERGENCY GENERATOR	17.11	NO. 2 DIESEL FUEL	10.9	MMBTU/H	Nitrogen Oxides (NOx)	N		6.4	G/KW-H	BACT-PSD
CA-1213	MOUNTAINVIEW POWER COMPANY LLC	04/21/2006 ACT	EMERGENCY POWER IC ENGINE	17.11	DIESEL	2155	BHP	Nitrogen Oxides (NOx)	N		0		BACT-PSD
IA-0076	JOHN DEERE PRODUCT ENGINEERING CENTER	03/23/2005 ACT	TEST CELL	17.11	DIESEL	24.5	GAL/H	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES.	1.52	LB/MMBTU	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	FIRE PUMP	17.11	DIESEL #2	540	HP	Nitrogen Oxides (NOx)	N	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 3 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	2.8	G/B-HP-H	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	EMERGENCY GENERATOR	17.11	DIESEL	1500	KW	Nitrogen Oxides (NOx)	N	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	4.5	G/B-HP-H	BACT-PSD
KS-0028	NEARMAN CREEK POWER STATION	10/18/2005 ACT	EMERGENCY BLACK START GENERATOR	17.11	NO. 2 FUEL OIL	24.1	MMBTU/H	Nitrogen Oxides (NOx)	N	EMERGENCY DIESEL GENERATORS HAVE NOT BEEN REQUIRED TO INSTALL ADDITIONAL NOX CONTROLS BECAUSE OF INTERMITTENT OPERATION.	84.8	LB/H	BACT-PSD
LA-0211	GARYVILLE REFINERY	12/27/2006 ACT	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)	17.11	DIESEL			Nitrogen Oxides (NOx)	N	USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS	0.031	LB/HP-H	BACT-PSD
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	08/15/2007 ACT	FIREWATER PUMP DIESEL ENGINE	17.11	DIESEL	660	HP	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)	10.07	LB/H	BACT-PSD
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	08/15/2007 ACT	FIREWATER PUMP DIESEL ENGINE	17.11	DIESEL	525	HP	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)	6.74	LB/H	BACT-PSD
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	08/15/2007 ACT	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	17.11	DIESEL	2168	HP EACH	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN INCORPORATING FUEL INJECTION TIMING RETARDATION (ITR)	37.95	LB/H	BACT-PSD
MN-0071	FAIRBAULT ENERGY PARK	06/05/2007 ACT	EMERGENCY GENERATOR	17.11	NO. 2	1750	KW	Nitrogen Oxides (NOx)	N		0.024	LB/HP-H	BACT-PSD
MS-0086	CHEVRON PRODUCTS COMPANY, PASCAGOULA REFINERY	05/08/2007 ACT	TEMPORARY, PORTABLE CRUDE I GENERATOR	17.11	DIESEL			Nitrogen Oxides (NOx)	A	SELECTIVE CATALYTIC REDUCTION (SCR)	1.3	LB/H	BACT-PSD
NV-0045	SLOAN QUARRY	12/11/2006 ACT	LARGE INTERNAL COMBUSTION ENGINE	17.11	DIESEL OIL	12	GAL/H	Nitrogen Oxides (NOx)	N	N/A	0.058	LB/T	BACT-PSD
WA-0328	BP CHERRY POINT COGENERATION PROJECT	01/11/2005 ACT	EMERGENCY GENERATOR	17.11	DIESEL FUEL	1.5	MW	Nitrogen Oxides (NOx)	P	THE ENGINE MUST BE NEW AND MUST SATISFY THE FEDERAL ENGINE STANDARDS OF 40 CFR 89 FOR YEAR OF PURCHASE.	0		BACT-PSD
WA-0329	DARRINGTON ENERGY COGENERATION POWER PLANT	02/11/2005 ACT	STANDBY GENERATOR	17.11	DIESEL FUEL	1	MW	Nitrogen Oxides (NOx)	P	ENGINE MUST BE NEW AND SATISFY FEDERAL STANDARDS @ 40 CFR 89	0		BACT-PSD
AK-0066	ENDICOTT PRODUCTION FACILITY, LIBERTY DEVELOPMENT PROJECT		EU ID 58, CAMP ENGINE 3	17.11	DISTILLATE	1041	HP	Nitrogen Oxides (NOx)	N	GOOD COMBUSTION PRACTICES	4.7	G/HP-H	BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	03/31/2010 ACT	Caterpillar 3215C Black Start Generator (1)	17.11	ULSD	1500	KW-e	Nitrogen Oxides (NOx)	A	Turbocharger and Aftercooler	6.4	G/KW-H	BACT-PSD
AK-0073	INTERNATIONAL STATION POWER PLANT	04/14/2010 ACT	Fuel Combustion	17.11	Diesel	1500	kW-e	Nitrogen Oxides (NOx)	A	Black Start diesel fired engine EU 13 shall be equipped with turbo charging and after cooling. The turbo charger reduces NOx emissions by boosting the pressure and temperature of the air entering the engine allowing more fuel to be added to increase power output. This translates into higher combustion efficiency and reduced emissions.	6.4	G/KW-H	BACT-PSD
AL-0251	HILLABEE ENERGY CENTER	07/09/2008 ACT	EMERGENCY GENERATOR	17.11	DIESEL	600	EKW	Nitrogen Oxides (NOx)	N	GOOD COMBUSTION PRACTICES	0		BACT-PSD
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	06/13/2007 ACT	EMERGENCY ENGINE	17.11	DIESEL	2000	KW	Nitrogen Oxides (NOx)	N	OPERATIONAL RESTRICTION OF 50 HR/YR	6	G/KW-H	BACT-PSD
FL-0310	SHADY HILLS GENERATING STATION	05/13/2008 ACT	2.5 MW EMERGENCY GENERATOR	17.11	ULTRA LOW S OIL	2.5	MW	Nitrogen Oxides (NOx)	P	PURCHASE MODEL IS AT LEAST AS STRINGENT AS THE BACT VALUES, UNDER EPA CERTIFICATION.	6.9	G/HP-H	BACT-PSD
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	03/19/2010 ACT	Emergency Generators, Two 2682 HP EA	17.11	ULSD	0		Nitrogen Oxides (NOx)	N		6.4	G/KW-H	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	07/01/2008 EST	EMERGENCY GENERATOR	17.11	DIESEL	700	KW	Nitrogen Oxides (NOx)	N		6.2	G/KW-H	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	07/01/2008 EST	FIRE PUMP ENGINE	17.11	DIESEL	575	HP	Nitrogen Oxides (NOx)	N		3.9	G/KW-H	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	04/29/2008 ACT	2 MW EMERGENCY GENERATOR, SRC25	17.11	ASTM #1, 2, DIESEL	2000	KW	Nitrogen Oxides (NOx)	N	GOOD COMBUSTION PRACTICES. EPA CERTIFIED PER NSPS IIII	0		BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	04/29/2008 ACT	500 KW EMERGENCY GENERATOR, FIRE PUMP, SRC26	17.11	ASTM #1, 2, DIESEL	500	KW	Nitrogen Oxides (NOx)	N	GOOD COMBUSTION PRACTICES. EPA CERTIFICATION PER NSPS IIII.	0		BACT-PSD
ID-0018	LANGLEY GULCH POWER PLANT	06/07/2009 ACT	EMERGENCY GENERATOR ENGINE	17.11	DIESEL	750	KW	Nitrogen Oxides (NOx)	P	TIER 2 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)	6.4	G/KW-H	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
LA-0204	PLAQUEMINE PVC PLANT	03/03/2008 ACT	LARGE EMERGENCY ENGINES	17.11	DIESEL			Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND GASEOUS FUEL BURNING	3.2	LB/MMBTU	BACT-PSD
LA-0231	LAKE CHARLES GASIFICATION FACILITY	09/24/2008 ACT	FIRE WATER DIESEL PUMPS (3)	17.11	DIESEL	575	HP EACH	Nitrogen Oxides (NOx)	P	COMPLY WITH 40 CFR 60 SUBPART IIII	6.02	LB/H	BACT-PSD
LA-0231	LAKE CHARLES GASIFICATION FACILITY	09/24/2008 ACT	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	17.11	DIESEL	1341	HP EACH	Nitrogen Oxides (NOx)	P	COMPLY WITH 40 CFR 60 SUBPART IIII	17.09	LB/H	BACT-PSD
NV-0047	NELLIS AIR FORCE BASE	09/26/2007 ACT	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)	17.11	DIESEL OIL			Nitrogen Oxides (NOx)	B	TURBOCHARGER AND AFTERCOOLER	7.58	G/B-HP-H	BACT-PSD
NV-0049	HARRAH'S OPERATING COMPANY, INC.	03/18/2009 EST	LARGE INTERNAL COMBUSTION ENGINES (>600 HP) - UNIT HA13	17.11	DIESEL OIL	1232	HP	Nitrogen Oxides (NOx)	P	THE UNIT IS EQUIPPED WITH A TURBOCHARGER.	0.024	LB/HP-H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	12/21/2007 ACT	EMERGENCY GENERATOR	17.11	DIESEL FUEL OIL	2922	HP	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, IGNITION TIMING RETARD, TURBOCHARGER, AND LOW-TEMPERATURE AFTERCOOLER	26.47	LB/H	BACT-PSD
OK-0128	MID AMERICAN STEEL ROLLING MILL	03/26/2008 ACT	Emergency Generator	17.11	No. 2 diesel	1200	HP	Nitrogen Oxides (NOx)	P	500 hours per year operations	15.6	LB/H	BACT-PSD
OK-0129	CHOUTEAU POWER PLANT	06/19/2008 ACT	EMERGENCY DIESEL GENERATOR (2200 HP)	17.11	LOW SULFUR DIESEL	2200	HP	Nitrogen Oxides (NOx)	N		23.15	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	01/10/2008 ACT	FIRE WATER DIESEL PUMP	17.11	DIESEL	525	HP	Nitrogen Oxides (NOx)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	5.9	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	01/10/2008 ACT	DIESEL EMERGENCY GENERATOR	17.11	DIESEL	1400	HP	Nitrogen Oxides (NOx)	N		11.41	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/25/2008 ACT	FIRE WATER DIESEL PUMP	17.11	DIESEL	525	HP	Nitrogen Oxides (NOx)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	5.9	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/25/2008 ACT	DIESEL EMERGENCY GENERATOR	17.11	DIESEL	1400	HP	Nitrogen Oxides (NOx)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	11.41	LB/H	BACT-PSD
AK-0072	DUTCH HARBOR POWER PLANT	07/14/2011 ACT	EU 15 Caterpillar C-280-16	17.11	ULSD	4400	KW	Nitrogen Oxides (NOx)	P	Engine has turbo charger and after cooler installed as part of the design	9.8	G/KW-H	BACT-PSD
AK-0076	POINT THOMSON PRODUCTION FACILITY	08/20/2012 ACT	Combustion of Diesel by ICEs	17.11	ULSD	1750	kW	Nitrogen Oxides (NOx)	N		6.4	G/KW-H	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	EMERGENCY IC ENGINE	17.11	DIESEL	2683	HP	Nitrogen Oxides (NOx)	N		6.4	G/KW-H	BACT-PSD
FL-0327	ANADARKO - PHEONIX PROSPECT	06/13/2011 ACT	Main Propulsion Engines	17.11	Diesel	0		Nitrogen Oxides (NOx)	P	Use of good combustion and maintenance practices, Power Management System, and NOx Concentration Maintenance System as described in the OCS permit application.	12.7	G/KW-H	BACT-PSD
FL-0327	ANADARKO - PHEONIX PROSPECT	06/13/2011 ACT	Emergency Engine	17.11	Diesel	0		Nitrogen Oxides (NOx)	P	Limited use of 24 hours/week and recordkeeping of operation.	9.4	TONS PER PROJECT	BACT-PSD
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	09/23/2011 ACT	2000 KW Emergency Equipment	17.11		0		Nitrogen Oxides (NOx)	P	See Pollutant Notes.	6.4	G/KW-H	BACT-PSD
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	09/23/2011 ACT	600 HP Emergency Equipment	17.11	Ultra-Low Sulfur Oil	0		Nitrogen Oxides (NOx)	P	See Pollutant Notes.	3	G/HP-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Emergency Generator	17.11	diesel fuel	142	GAL/H	Nitrogen Oxides (NOx)	P	good combustion practices	6	G/KW-H	BACT-PSD
MI-0394	WARREN TECHNICAL CENTER	02/29/2012 ACT	Four (4) Emergency Generators	17.11	Diesel	2280	KW	Nitrogen Oxides (NOx)	P	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	6.93	G/KW-H	BACT-PSD
MI-0394	WARREN TECHNICAL CENTER	02/29/2012 ACT	Nine (9) DRUPS Emergency Generators	17.11	Diesel	3010	KW	Nitrogen Oxides (NOx)	P	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	07/13/2012 ACT	Nine (9) DRUPS Emergency Generators	17.11	Diesel	3010	KW	Nitrogen Oxides (NOx)	P	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.98	G/KW-H	BACT-PSD
MI-0395	WARREN TECHNICAL CENTER	07/13/2012 ACT	Four (4) Emergency Generators	17.11	Diesel	2500	KW	Nitrogen Oxides (NOx)	P	No add-on control, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	7.13	G/KW-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	EMERGENCY GENERATORS 1 THRU 8	17.11	DIESEL	757	HP	Nitrogen Oxides (NOx)	P	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD
PA-0271	MERCK & CO. WESTPOINT	02/23/2007 ACT	MOBILE EMERGENCY GENERATOR	17.11	DIESEL			Nitrogen Oxides (NOx)	N		6.8	G/B-HP-H	OTHER CASE-BY-CASE
NV-0050	MGM MIRAGE	11/30/2009 ACT	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	17.11	DIESEL OIL	2206	HP	Nitrogen Oxides (NOx)	P	TURBOCHARGING, AFTER-COOLING, AND LEAN-BURN TECHNOLOGY	0.0131	LB/HP-H	Other Case-by-Case
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	10/10/2012 ACT	Emergency Generator	17.11	Diesel	0		Nitrogen Oxides (NOx)	N		4.93	G/B-HP-H	OTHER CASE-BY-CASE
NJ-0073	TRIGEN	03/08/2008 ACT	DUAL FUEL ENGINES ON 100 % DISTILLATE FUEL OIL	17.11	DISTILLATE FUEL OIL	1	MMGAL/YR	Nitrogen Oxides (NOx)	N		12	G/B-HP-H	RACT
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/2005 ACT	FIRE WATER PUMPS NOS 1 AND 2	17.11	NO. 2 DIESEL FUEL	5.46	MMBTU/H	Particulate Matter (PM)	N		0.2	G/KW-H	BACT-PSD
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/2005 ACT	EMERGENCY GENERATOR	17.11	NO. 2 DIESEL FUEL	10.9	MMBTU/H	Particulate Matter (PM)	N		0.02	G/KW-H	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	FIRE PUMP	17.11	DIESEL #2	540	HP	Particulate Matter (PM)	N	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 3 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	0.15	G/B-HP-H	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	EMERGENCY GENERATOR	17.11	DIESEL	1500	KW	Particulate Matter (PM)	N	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	0.15	G/B-HP-H	BACT-PSD
MN-0071	FAIRBAULT ENERGY PARK	06/05/2007 ACT	EMERGENCY GENERATOR	17.11	NO. 2	1750	KW	Particulate Matter (PM)	N		0.0007	LB/HP-H	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	07/01/2008 EST	EMERGENCY GENERATOR	17.11	DIESEL	700	KW	Particulate Matter (PM)	N		0.2	G/KW-H	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	07/01/2008 EST	FIRE PUMP ENGINE	17.11	DIESEL	575	HP	Particulate Matter (PM)	N		0.2	G/KW-H	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	04/29/2008 ACT	2 MW EMERGENCY GENERATOR, SRC25	17.11	ASTM #1, 2, DIESEL	2000	KW	Particulate Matter (PM)	P	ULSD FUEL, GOOD COMBUSTION PRACTICES, EPA CERTIFIED PER NSPS IIII	0		BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	04/29/2008 ACT	500 KW EMERGENCY GENERATOR, FIRE PUMP, SRC26	17.11	ASTM #1, 2, DIESEL	500	KW	Particulate Matter (PM)	P	ULSD FUEL, EPA CERTIFICATION PER NSPS IIII	0		BACT-PSD
ID-0018	LANGLEY GULCH POWER PLANT	06/07/2009 ACT	EMERGENCY GENERATOR ENGINE	17.11	DIESEL	750	KW	Particulate Matter (PM)	P	TIER 2 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)	0.2	G/KW-H	BACT-PSD
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	06/03/2008 ACT	EMERGENCY DIESEL GENERATORS (2)	17.11	LOW SULFUR DIESEL	1000	KW	Particulate Matter (PM)	P	ULTRA LOW SULFUR DIESEL AT 15 PPM S.	0.19	LB/H	BACT-PSD
CO-0055	LAMAR LIGHT & POWER POWER PLANT	02/03/2006 ACT	DIESEL ENGINES FOR SWITCHING, LOCOMOTIVE & FIRE PUMP	17.11	DIESEL	1500	HP	Particulate matter, filterable < 10 µ (FPM10)	P	LOW SULFUR FUEL - %0.05 BY WEIGHT	0.016	LB/MMBTU	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	FIRE PUMP	17.11	DIESEL #2	540	HP	Particulate matter, filterable < 10 µ (FPM10)	N	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 3 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	0.15	G/B-HP-H	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	EMERGENCY GENERATOR	17.11	DIESEL	1500	KW	Particulate matter, filterable < 10 µ (FPM10)	N	NO SPECIFIC CONTROL TECHNOLOGY IS SPECIFED. ENGINE IS REQUIRED TO MEET LIMITS ESTABLISHED AS BACT (TIER 2 NONROAD). THIS COULD REQUIRE ANY NUMBER OF CONTROL TECHNOLOGIES AND OPERATIONAL REQ. TO MEET THE BACT STANDARD.	0.15	G/B-HP-H	BACT-PSD
LA-0211	GARYVILLE REFINERY	12/27/2006 ACT	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)	17.11	DIESEL			Particulate matter, filterable < 10 µ (FPM10)	N	USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS	0.0022	LB/HP-H	BACT-PSD
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	08/15/2007 ACT	FIREWATER PUMP DIESEL ENGINE	17.11	DIESEL	660	HP	Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL	0.64	LB/H	BACT-PSD
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	08/15/2007 ACT	FIREWATER PUMP DIESEL ENGINE	17.11	DIESEL	525	HP	Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL	0.28	LB/H	BACT-PSD
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	08/15/2007 ACT	DIESEL EMERGENCY GENERATOR NOS. 1 & 2	17.11	DIESEL	2168	HP EACH	Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, AND USE OF LOW SULFUR AND LOW ASH DIESEL	0.69	LB/H	BACT-PSD
MN-0071	FAIRBAULT ENERGY PARK	06/05/2007 ACT	EMERGENCY GENERATOR	17.11	NO. 2	1750	KW	Particulate matter, filterable < 10 µ (FPM10)	N		0.0004	LB/HP-H	BACT-PSD
OK-0118	HUGO GENERATING STA	02/09/2007 ACT	EMERGENCY DIESEL INTERNAL COMBUSTION ENGINES	17.11				Particulate matter, filterable < 10 µ (FPM10)	P	USE OF LOW SULFUR NO.2 FUEL OIL COMBINED WITH GOOD COMBUSTION PRACTICES AND LIMITED ANNUAL OPERATION	0		BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	07/01/2008 EST	EMERGENCY GENERATOR	17.11	DIESEL	700	KW	Particulate matter, filterable < 10 µ (FPM10)	N		0.2	G/KW-H	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	07/01/2008 EST	FIRE PUMP ENGINE	17.11	DIESEL	575	HP	Particulate matter, filterable < 10 µ (FPM10)	N		0.2	G/KW-H	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	04/29/2008 ACT	2 MW EMERGENCY GENERATOR, SRC25	17.11	ASTM #1, 2, DIESEL	2000	KW	Particulate matter, filterable < 10 µ (FPM10)	P	ULSD FUEL, GOOD COMBUSTION PRACTICES, EPA CERTIFIED PER NSPS IIII	0		BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	04/29/2008 ACT	500 KW EMERGENCY GENERATOR, FIRE PUMP, SRC26	17.11	ASTM #1, 2, DIESEL	500	KW	Particulate matter, filterable < 10 µ (FPM10)	P	ULSD FUEL, EPA CERTIFICATION PER NSPS IIII	0		BACT-PSD
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	06/03/2008 ACT	EMERGENCY DIESEL GENERATORS (2)	17.11	LOW SULFUR DIESEL	1000	KW	Particulate matter, filterable < 10 µ (FPM10)	P	ULTRA LOW SULFUR DIESEL AT 15 PPM S	0.19	LB/H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	12/21/2007 ACT	EMERGENCY GENERATOR	17.11	DIESEL FUEL OIL	2922	HP	Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.87	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	01/10/2008 ACT	FIRE WATER DIESEL PUMP	17.11	DIESEL	525	HP	Particulate matter, filterable < 10 µ (FPM10)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.41	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	01/10/2008 ACT	DIESEL EMERGENCY GENERATOR	17.11	DIESEL	1400	HP	Particulate matter, filterable < 10 µ (FPM10)	N		0.2	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/25/2008 ACT	FIRE WATER DIESEL PUMP	17.11	DIESEL	525	HP	Particulate matter, filterable < 10 µ (FPM10)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.41	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/25/2008 ACT	DIESEL EMERGENCY GENERATOR	17.11	DIESEL	1400	HP	Particulate matter, filterable < 10 µ (FPM10)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.2	LB/H	BACT-PSD
LA-0251	FLOPAM INC. FACILITY	04/26/2011 ACT	Large Generator Engines (17 units)	17.11	Diesel	0		Particulate matter, filterable < 10 µ (FPM10)	N		0.01	LB/H	BACT-PSD
NJ-0080	HESS NEWARK ENERGY CENTER	11/01/2012 ACT	Emergency Generator	17.11	ULSD	200	H/YR	Particulate matter, filterable < 10 µ (FPM10)	N		0.66	LB/H	BACT-PSD
NY-0101	CORNELL COMBINED HEAT & POWER PROJECT	06/03/2008 ACT	EMERGENCY DIESEL GENERATORS (2)	17.11	LOW SULFUR DIESEL	1000	KW	Particulate matter, filterable < 2.5 µ (FPM2.5)	P	ULTRA LOW SULFUR DIESEL AT 15 PPM S	0.19	LB/H	BACT-PSD
AK-0072	DUTCH HARBOR POWER PLANT	07/14/2011 ACT	EU 15 Caterpillar C-280-16	17.11	ULSD	4400	KW	Particulate matter, filterable < 2.5 µ (FPM2.5)	P	Positive Crankcase Ventilation Installed as part of the design	0.5	G/KW-H	BACT-PSD
NJ-0080	HESS NEWARK ENERGY CENTER	11/01/2012 ACT	Emergency Generator	17.11	ULSD	200	H/YR	Particulate matter, filterable < 2.5 µ (FPM2.5)	P	use of ULSD, a low sulfur clean fuel	0		BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	03/31/2010 ACT	Caterpillar 3215C Black Start Generator (1)	17.11	ULSD	1500	KW-e	Particulate matter, total (TPM)	P	Good Combustion Practices	0.03	G/HP-H	BACT-PSD
AL-0251	HILLABEE ENERGY CENTER	07/09/2008 ACT	EMERGENCY GENERATOR	17.11	DIESEL	600	EKW	Particulate matter, total (TPM)	N	LOW SULFUR DIESEL FUEL	0		BACT-PSD
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	06/13/2007 ACT	EMERGENCY ENGINE	17.11	DIESEL	2000	KW	Particulate matter, total (TPM)	N	OPERATIONAL RESTRICTION OF 50 HR/YR; USE OF ULTRA LOW SULFUR FUEL NOT TO EXCEED 15 PPMVD FUEL SULFUR	0.2	G/KW-H	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	03/19/2010 ACT	Emergency Generators, Two 2682 HP EA	17.11	ULSD	0		Particulate matter, total (TPM)	N		0.2	G/KW-H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	10/15/2007 ACT	FIRE PUMP	17.11	ULTRA LOW SULFUR DIESEL	525	HP	Particulate matter, total (TPM)	P	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.15	G/HP-H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	10/15/2007 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	2000	KW	Particulate matter, total (TPM)	P	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.2	G/KW-H	BACT-PSD
SC-0114	GP ALLENDALE LP	01/10/2008 ACT	FIRE WATER DIESEL PUMP	17.11	DIESEL	525	HP	Particulate matter, total (TPM)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.41	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	01/10/2008 ACT	DIESEL EMERGENCY GENERATOR	17.11	DIESEL	1400	HP	Particulate matter, total (TPM)	N		0.25	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/25/2008 ACT	FIRE WATER DIESEL PUMP	17.11	DIESEL	525	HP	Particulate matter, total (TPM)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.41	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/25/2008 ACT	DIESEL EMERGENCY GENERATOR	17.11	DIESEL	1400	HP	Particulate matter, total (TPM)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.25	LB/H	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	EMERGENCY IC ENGINE	17.11	DIESEL	2683	HP	Particulate matter, total (TPM)	P	USE ULTRA LOW SULFUR FUEL	0.2	G/KW-H	BACT-PSD
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	09/23/2011 ACT	2000 KW Emergency Equipment	17.11		0		Particulate matter, total (TPM)	P	See Pollutant Notes.	0.2	G/KW-H	BACT-PSD
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	09/23/2011 ACT	600 HP Emergency Equipment	17.11	Ultra-Low Sulfur Oil	0		Particulate matter, total (TPM)	P	See Pollutant Notes.	0.15	G/HP-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Emergency Generator	17.11	diesel fuel	142	GAL/H	Particulate matter, total (TPM)	P	good combustion practices	0.2	G/KW-H	BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	03/31/2010 ACT	Caterpillar 3215C Black Start Generator (1)	17.11	ULSD	1500	KW-e	Particulate matter, total < 10 µ (TPM10)	P	Good Combustion Practices	0.03	G/HP-H	BACT-PSD
AK-0073	INTERNATIONAL STATION POWER PLANT	04/14/2010 ACT	Fuel Combustion	17.11	Diesel	1500	kW-e	Particulate matter, total < 10 µ (TPM10)	P	Black Start diesel fired engine EU 13 shall be equipped with turbo charging and after cooling. The turbo charger reduces NOx emissions by boosting the pressure and temperature of the air entering the engine allowing more fuel to be added to increase power output. This translates into higher combustion efficiency and reduced emissions.	0.03	G/HP-H	BACT-PSD
FL-0310	SHADY HILLS GENERATING STATION	05/13/2008 ACT	2.5 MW EMERGENCY GENERATOR	17.11	ULTRA LOW S OIL	2.5	MW	Particulate matter, total < 10 µ (TPM10)	P	FIRING ULSO WITH A MAXIMUM SULFUR CONTENT OF 0.0015% BY WEIGHT AND A MAXIMUM HOURS OF OPERATION OF 500 HOUR/YR.	0.4	G/HP-H	BACT-PSD
FL-0310	SHADY HILLS GENERATING STATION	05/13/2008 ACT	2.5 MW EMERGENCY GENERATOR	17.11	ULTRA LOW S OIL	2.5	MW	Particulate matter, total < 10 µ (TPM10)	P	FIRING ULSO WITH A MAXIMUM SULFUR CONTENT OF 0.0015% BY WEIGHT AND A MAXIMUM HOURS OF OPERATION OF 500 HOUR/YR.	0.4	G/HP-H	BACT-PSD
LA-0204	PLAQUEMINE PVC PLANT	03/03/2008 ACT	LARGE EMERGENCY ENGINES	17.11	DIESEL			Particulate matter, total < 10 µ (TPM10)	P	GOOD COMBUSTION PRACTICES AND GASEOUS FUEL BURNING	0.1	LB/MMBTU	BACT-PSD
LA-0231	LAKE CHARLES GASIFICATION FACILITY	09/24/2008 ACT	FIRE WATER DIESEL PUMPS (3)	17.11	DIESEL	575	HP EACH	Particulate matter, total < 10 µ (TPM10)	P	COMPLY WITH 40 CFR 60 SUBPART IIII	0.08	LB/H	BACT-PSD
LA-0231	LAKE CHARLES GASIFICATION FACILITY	09/24/2008 ACT	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	17.11	DIESEL	1341	HP EACH	Particulate matter, total < 10 µ (TPM10)	P	COMPLY WITH 40 CFR 60 SUBPART IIII	0.06	LB/H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	10/15/2007 ACT	FIRE PUMP	17.11	ULTRA LOW SULFUR DIESEL	525	HP	Particulate matter, total < 10 µ (TPM10)	P	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.31	LB/MMBTU	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	10/15/2007 ACT	EMERGENCY GENERATOR	17.11	ULTRA LOW SULFUR DIESEL	2000	KW	Particulate matter, total < 10 µ (TPM10)	P	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.0573	LB/MMBTU	BACT-PSD
OK-0128	MID AMERICAN STEEL ROLLING MILL	03/26/2008 ACT	Emergency Generator	17.11	No. 2 diesel	1200	HP	Particulate matter, total < 10 µ (TPM10)	N		0.84	LB/H	BACT-PSD
OK-0129	CHOUTEAU POWER PLANT	06/19/2008 ACT	EMERGENCY DIESEL GENERATOR (2200 HP)	17.11	LOW SULFUR DIESEL	2200	HP	Particulate matter, total < 10 µ (TPM10)	N		0.72	LB/H	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	EMERGENCY IC ENGINE	17.11	DIESEL	2683	HP	Particulate matter, total < 10 µ (TPM10)	P	USE ULTRA LOW SULFUR FUEL	0.2	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Emergency Generator	17.11	diesel fuel	142	GAL/H	Particulate matter, total < 10 µ (TPM10)	P	good combustion practices	0.2	G/KW-H	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	08/16/2011 ACT	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	1250	HP	Particulate matter, total < 10 µ (TPM10)	P	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	0.15	G/HP-H	BACT-PSD
AK-0071	INTERNATIONAL STATION POWER PLANT	03/31/2010 ACT	Caterpillar 3215C Black Start Generator (1)	17.11	ULSD	1500	KW-e	Particulate matter, total < 2.5 µ (TPM2.5)	P	Good Combustion Practices	0.03	G/HP-H	BACT-PSD
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	06/13/2007 ACT	EMERGENCY ENGINE	17.11	DIESEL	2000	KW	Particulate matter, total < 2.5 µ (TPM2.5)	N	OPERATIONAL RESTRICTION OF 50 HR/YR; USE OF ULTRA LOW SULFUR FUEL NOT TO EXCEED 15 PPMVD	0.2	G/KW-H	BACT-PSD
AK-0076	POINT THOMSON PRODUCTION FACILITY	08/20/2012 ACT	Combustion of Diesel by ICEs	17.11	ULSD	1750	kW	Particulate matter, total < 2.5 µ (TPM2.5)	N		0.2	G/KW-H	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	EMERGENCY IC ENGINE	17.11	DIESEL	2683	HP	Particulate matter, total < 2.5 µ (TPM2.5)	P	USE ULTRA LOW SULFUR FUEL	0.2	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Emergency Generator	17.11	diesel fuel	142	GAL/H	Particulate matter, total < 2.5 µ (TPM2.5)	P	good combustion practices	0.2	G/KW-H	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	08/16/2011 ACT	EMERGENCY DIESEL GENERATOR	17.11	DIESEL	1250	HP	Particulate matter, total < 2.5 µ (TPM2.5)	P	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	0.15	G/HP-H	BACT-PSD
PA-0271	MERCK & CO. WESTPOINT	02/23/2007 ACT	MOBILE EMERGENCY GENERATOR	17.11	DIESEL			Particulate matter, filterable (FPM)	N		0.16	G/B-HP-H	OTHER CASE-BY-CASE
PA-0271	MERCK & CO. WESTPOINT	02/23/2007 ACT	MOBILE EMERGENCY GENERATOR	17.11	DIESEL			Particulate matter, filterable < 10 µ (FPM10)	N		0.16	G/B-HP-H	OTHER CASE-BY-CASE
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)	17.11	DIESEL OIL			Particulate matter, filterable < 10 µ (FPM10)	B	TURBOCHARGER AND AFTERCOOLER	0.084	G/B-HP-H	OTHER CASE-BY-CASE
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	LARGE INTERNAL COMBUSTION ENGINES (>600 HP) - UNIT HA13	17.11	DIESEL OIL	1232	HP	Particulate matter, filterable < 10 µ (FPM10)	P	THE UNIT IS EQUIPPED WITH A TURBOCHARGER.	0.0007	LB/HP-H	Other Case-by-Case
NV-0050	MGM MIRAGE	11/30/2009 ACT	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	17.11	DIESEL OIL	2206	HP	Particulate matter, filterable < 10 µ (FPM10)	P	TURBOCHARGER AND GOOD COMBUSTION PRACTICES	0.0001	LB/HP-H	Other Case-by-Case
NJ-0079	WOODBRIDGE ENERGY CENTER	07/25/2012 ACT	Emergency Generator	17.11	Ultra Low Sulfur distillate Diesel	100	H/YR	Particulate matter, total < 10 µ (TPM10)	P	Use of ULSD oil	0.13	LB/H	OTHER CASE-BY-CASE

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	10/10/2012 ACT	Emergency Generator	17.11	Diesel	0		Particulate matter, total < 10 µ (TPM10)	N		0.02	G/B-HP-H	OTHER CASE-BY-CASE
AK-0081	POINT THOMSON PRODUCTION FACILITY	06/12/2013 ACT	Combustion	17.11	ULSD	610	hp	Particulate matter, total < 2.5 µ (TPM2.5)	P	Good operation and combustion practices	0.15	G/KW-H	OTHER CASE-BY-CASE
NJ-0079	WOODBRIDGE ENERGY CENTER	07/25/2012 ACT	Emergency Generator	17.11	Ultra Low Sulfur distillate Diesel	100	H/YR	Particulate matter, total < 2.5 µ (TPM2.5)	P	Use of ULSD oil	0.13	LB/H	OTHER CASE-BY-CASE
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	10/10/2012 ACT	Emergency Generator	17.11	Diesel	0		Particulate matter, total < 2.5 µ (TPM2.5)	N		0.02	G/B-HP-H	OTHER CASE-BY-CASE
AK-0062	BADAMI DEVELOPMENT FACILITY	08/19/2005 ACT	CUMMINS IC ENGINE GENERATOR	17.11	DIESEL FUEL	1855	HP	Sulfur Dioxide (SO2)	P	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	0.15	% BY WT	BACT-PSD
CO-0055	LAMAR LIGHT & POWER POWER PLANT	02/03/2006 ACT	DIESEL ENGINES FOR SWITCHING, LOCOMOTIVE & FIRE PUMP	17.11	DIESEL	1500	HP	Sulfur Dioxide (SO2)	P	LOW SULFUR FUEL. LESS TAN 0.05 BY WHEIGHT	0.06	LB/MMBTU	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	FIRE PUMP	17.11	DIESEL #2	540	HP	Sulfur Dioxide (SO2)	P	BURN LOW-SULFUR DIESEL FUEL. 0.05% BY WEIGHT OR LESS NOT TO EXCEED THE NSPS REQUIREMENT.	0.17	G/B-HP-H	BACT-PSD
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	EMERGENCY GENERATOR	17.11	DIESEL	1500	KW	Sulfur Dioxide (SO2)	P	BURN LOW-SULFUR DIESEL FUEL. 0.05% BY WEIGHT OR LESS NOT TO EXCEED THE NSPS REQUIREMENT.	0.17	G/B-HP-H	BACT-PSD
KS-0028	NEARMAN CREEK POWER STATION	10/18/2005 ACT	EMERGENCY BLACK START GENERATOR	17.11	NO. 2 FUEL OIL	24.1	MMBTU/H	Sulfur Dioxide (SO2)	N	GOOD COMBUSTION CONTROL	1.2	LB/H	BACT-PSD
LA-0211	GARYVILLE REFINERY	12/27/2006 ACT	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)	17.11	DIESEL			Sulfur Dioxide (SO2)	N		0.02	MAX LB/H	BACT-PSD
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	09/07/2007 ACT	EMERGENCY POWER GENERATION - DIESEL	17.11	DIESEL			Sulfur Dioxide (SO2)	P	LIMITED HOURS, LIMITED SULFUR IN FUEL	0.05	%	BACT-PSD
MN-0071	FAIRBAULT ENERGY PARK	06/05/2007 ACT	EMERGENCY GENERATOR	17.11	NO. 2	1750	KW	Sulfur Dioxide (SO2)	N		0.0004	LB/HP-H	BACT-PSD
OK-0118	HUGO GENERATING STA	02/09/2007 ACT	EMERGENCY DIESEL INTERNAL COMBUSTION ENGINES	17.11				Sulfur Dioxide (SO2)	P	USE OF LOW SULFUR NO.2 FUEL OIL COMBINED WITH GOOD COMBUSTION PRACTICES AND LIMITED ANNUAL OPERATION	0		BACT-PSD
WA-0328	BP CHERRY POINT COGENERATION PROJECT	01/11/2005 ACT	EMERGENCY GENERATOR	17.11	DIESEL FUEL	1.5	MW	Sulfur Dioxide (SO2)	P	FUEL MUST SATISFY REQUIREMENTS OF ON-ROAD DIESEL SPECIFICATIONS AT TIME OF FUEL PURCHASE	0		BACT-PSD
AK-0066	ENDICOTT PRODUCTION FACILITY, LIBERTY DEVELOPMENT PROJECT		EU ID 58, CAMP ENGINE 3	17.11	DISTILLATE	1041	HP	Sulfur Dioxide (SO2)	P	LIMIT SULFUR IN FUEL	15	PPMW	BACT-PSD
AL-0251	HILLABEE ENERGY CENTER	07/09/2008 ACT	EMERGENCY GENERATOR	17.11	DIESEL	600	EKW	Sulfur Dioxide (SO2)	N	LOW SULFUR DIESEL FUEL	0		BACT-PSD
FL-0310	SHADY HILLS GENERATING STATION	05/13/2008 ACT	2.5 MW EMERGENCY GENERATOR	17.11	ULTRA LOW S OIL	2.5	MW	Sulfur Dioxide (SO2)	P	FIRING ULTRA LOW SULFUR OIL WITH A MAXIMUM HOURS OF OPERATION OF 500 HRS/YR.	0.0015	% S BY WT	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	07/01/2008 EST	EMERGENCY GENERATOR	17.11	DIESEL	700	KW	Sulfur Dioxide (SO2)	P	FUEL SULFUR LIMIT	0.23	G/KW-H	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	07/01/2008 EST	FIRE PUMP ENGINE	17.11	DIESEL	575	HP	Sulfur Dioxide (SO2)	P	LIMIT ON SULFUR IN FUEL	0.23	G/KW-H	BACT-PSD
LA-0231	LAKE CHARLES GASIFICATION FACILITY	09/24/2008 ACT	FIRE WATER DIESEL PUMPS (3)	17.11	DIESEL	575	HP EACH	Sulfur Dioxide (SO2)	P	COMPLY WITH 40 CFR 60 SUBPART IIII	0.01	LB/H	BACT-PSD
LA-0231	LAKE CHARLES GASIFICATION FACILITY	09/24/2008 ACT	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	17.11	DIESEL	1341	HP EACH	Sulfur Dioxide (SO2)	P	COMPLY WITH 40 CFR 60 SUBPART IIII	0.01	LB/H	BACT-PSD
NV-0047	NELLIS AIR FORCE BASE	09/26/2007 ACT	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)	17.11	DIESEL OIL			Sulfur Dioxide (SO2)	P	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.05%	0.02	G/B-HP-H	BACT-PSD
OK-0128	MID AMERICAN STEEL ROLLING MILL	03/26/2008 ACT	Emergency Generator	17.11	No. 2 diesel	1200	HP	Sulfur Dioxide (SO2)	P	500 hours per year, 0.05% sulfur diesel fuel	0.49	LB/H	BACT-PSD
OK-0129	CHOUTEAU POWER PLANT	06/19/2008 ACT	EMERGENCY DIESEL GENERATOR (2200 HP)	17.11	LOW SULFUR DIESEL	2200	HP	Sulfur Dioxide (SO2)	N	LOW SULFUR DIESEL 0.05%S	0.89	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	01/10/2008 ACT	FIRE WATER DIESEL PUMP	17.11	DIESEL	525	HP	Sulfur Dioxide (SO2)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.39	LB/H	BACT-PSD
SC-0114	GP ALLENDALE LP	01/10/2008 ACT	DIESEL EMERGENCY GENERATOR	17.11	DIESEL	1400	HP	Sulfur Dioxide (SO2)	N		5.4	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/25/2008 ACT	FIRE WATER DIESEL PUMP	17.11	DIESEL	525	HP	Sulfur Dioxide (SO2)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.39	LB/H	BACT-PSD
SC-0115	GP CLARENDON LP	02/25/2008 ACT	DIESEL EMERGENCY GENERATOR	17.11	DIESEL	1400	HP	Sulfur Dioxide (SO2)	P	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	5.4	LB/H	BACT-PSD
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	09/23/2011 ACT	2000 KW Emergency Equipment	17.11		0		Sulfur Dioxide (SO2)	P	See Pollutant Notes.	0.0015	% SULFUR	BACT-PSD
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	09/23/2011 ACT	600 HP Emergency Equipment	17.11	Ultra-Low Sulfur Oil	0		Sulfur Dioxide (SO2)	P	See Pollutant Notes.	0.0015	% SULFUR	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	EMERGENCY GENERATORS 1 THRU 8	17.11	DIESEL	757	HP	Sulfur Dioxide (SO2)	P	USE OF LOW SULFUR FUEL DIESEL, SULFUR CONTENT LESS THAN 0.0015 PERCENT. OPERATING HOURS LESS THAN 100 HOURS PER YEAR FOR MAINTENACE AND TESTING.	0		BACT-PSD
NV-0045	SLOAN QUARRY	12/11/2006 ACT	LARGE INTERNAL COMBUSTION ENGINE	17.11	DIESEL OIL	12	GAL/H	Sulfur Oxides (SOx)	P	USE OF LOW-SULFUR OIL	0.058	LB/T	BACT-PSD
NV-0049	HARRAH'S OPERATING COMPANY, INC.	03/18/2009 EST	LARGE INTERNAL COMBUSTION ENGINES (>600 HP) - UNIT HA13	17.11	DIESEL OIL	1232	HP	Sulfur Oxides (SOx)	P	THE UNIT SHALL COMBUST ONLY LOW-SULFUR DIESEL OIL WITH A SULFUR CONTENT LESS THAN 0.05%.	0.0004	LB/HP-H	BACT-PSD
NV-0050	MGM MIRAGE	05/22/2008 ACT	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	17.11	DIESEL OIL	2206	HP	Sulfur Oxides (SOx)	P	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.03%	0.0002	LB/HP-H	BACT-PSD

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-19. Summary of Identified NO_X Control Technology - Small Diesel Engines 500 hp and Less (RBLC 17.210)

Pollutant	Control Technology Used	Number of RBLC Entries (27 Total)
NO_X	None	13
	NSPS Subpart IIII Standards	3
	Turbocharger	3
	Aftercooler	3
	Limited Operation	2
	Non Road Engine Standards (Tiers I - IV)	1
	Ignition Timing Retard	1
	Intercooler	1
	SCR	NA

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-20. Summary of Identified $PM_{2.5}$ Control Technology - Small Diesel Engines 500 hp and Less (RBLC 17.210)

Pollutant	Control Technology Used	Number of RBLC Entries (48 Total)
$PM_{2.5}$	None	24
	Good Combustion Practice	17
	Limited Operation	5
	Non Road Engine Standards (Tiers I - IV)	1
	NSPS Subpart IIII	1
	Particulate Trap Filter	NA

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-21. Summary of Identified SO_2 Control Technology - Small Diesel Engines 500 hp and Less (RBLC 17.210)

Pollutant	Control Technology Used	Number of RBLC Entries (18 Total)
SO_2	None	5
	Limited Sulfur in Fuel	5
	Limited Operation	4
	Ultra Low Sulfur Diesel	2
	Good Combustion Practice	2

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-22. RBLC Control Technology Determinations for Small Diesel-fired Engines 500 hp and Less (RBLC 17.210)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	12/23/2010 ACT	Emergency Diesel Fire Pump, One 600 HP	17.21	ULSD	0		Nitrogen Dioxide (NO2)	N		3	G/HP-H	BACT-PSD
AZ-0051	DRAKE	04/12/2006 ACT	EMERGENCY GENERATOR	17.21	FUEL OIL #2	210	KW	Nitrogen Oxides (NOx)	N		4	G/KW-H	BACT-PSD
CA-1144	BLYTHE ENERGY PROJECT II	04/25/2007 ACT	FIRE PUMP	17.21	DIESEL	303	HP	Nitrogen Oxides (NOx)	N		7.5	LB/H	BACT-PSD
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	03/11/2010 ACT	EMERGENCY FIREWATER PUMP ENGINE	17.21	DIESEL	135	KW	Nitrogen Oxides (NOx)	N	OPERATIONAL RESTRICTION OF 50 HR/YR, OPERATE AS REQUIRED FOR FIRE SAFETY TESTING	3.8	G/KW-H	BACT-PSD
CA-1192	AVENAL ENERGY PROJECT	06/21/2011 ACT	EMERGENCY FIREWATER PUMP ENGINE	17.21	DIESEL	288	HP	Nitrogen Oxides (NOx)	P	EQUIPPED W/ A TURBOCHARGER AND AN INTERCOOLER/AFTERCOOLER	3.4	G/HP-H	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	EMERGENCY IC ENGINE	17.21	DIESEL	182	HP	Nitrogen Oxides (NOx)	N		4	G/KW-H	BACT-PSD
CA-1213	MOUNTAINVIEW POWER COMPANY LLC	04/21/2006 ACT	EMERGENCY FIRE IC ENGINE	17.21	DIESEL	375	BHP	Nitrogen Oxides (NOx)	N		0		BACT-PSD
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	12/23/2010 ACT	250 Kw Emergency Generator	17.21	ULSD	0		Nitrogen Oxides (NOx)	P	Use of inherently clean ultra low sulfur distillate (ULSD) fuel oil and GCP	4	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Fire Pump	17.21	diesel fuel	14	GAL/H	Nitrogen Oxides (NOx)	P	good combustion practices	3.75	G/KW-H	BACT-PSD
ID-0018	LANGLEY GULCH POWER PLANT	06/25/2010 ACT	FIRE PUMP ENGINE	17.21	DIESEL	235	KW	Nitrogen Oxides (NOx)	P	TIER 3 ENGINE-BASED GOOD COMBUSTION PRACTICES (GCP)	4	G/KW-H	BACT-PSD
LA-0192	CRESCENT CITY POWER	06/06/2005 ACT	DIESEL FIRED WATER PUMP	17.21				Nitrogen Oxides (NOx)	P	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	8.9	LB/H	BACT-PSD
LA-0204	PLAQUEMINE PVC PLANT	02/27/2009 ACT	SMALL EMERGENCY ENGINES	17.21	DIESEL			Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES AND GASEOUS FUEL BURNING	4.41	LB/MMBTU	BACT-PSD
LA-0224	ARSENAL HILL POWER PLANT	03/20/2008 ACT	DFP DIESEL FIRE PUMP	17.21	DIESEL	310	HP	Nitrogen Oxides (NOx)	N	USE OF LOW-SULFUR FUELS, LIMITING OPERATING HOURS AND PROPER ENGINE MAINTENANCE	9.61	LB/H	BACT-PSD
LA-0251	FLOPAM INC. FACILITY	04/26/2011 ACT	Small Generator Engine	17.21	diesel	193	hp	Nitrogen Oxides (NOx)	N		1.28	LB/H	BACT-PSD
LA-0251	FLOPAM INC. FACILITY	04/26/2011 ACT	Fire Pump Engines - 2 units	17.21	diesel	444	hp	Nitrogen Oxides (NOx)	N		5.82	LB/H	BACT-PSD
MD-0040	CPV ST CHARLES	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	17.21	DIESEL	300	HP	Nitrogen Oxides (NOx)	N		3	G/HP-H	BACT-PSD
MD-0040	CPV ST CHARLES	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY GENERATOR	17.21	DIESEL			Nitrogen Oxides (NOx)	N		4.8	G/HP-H	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/2005 ACT	IC ENGINE, EMERGENCY GENERATOR	17.21	DIESEL FUEL	11.4	MMBTU/H	Nitrogen Oxides (NOx)	N		36.48	LB/H	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/2005 ACT	IC ENGINE, EMERGENCY FIREWATER PUMP	17.21	DIESEL FUEL	11.4	MMBTU/H	Nitrogen Oxides (NOx)	N		36.48	LB/H	BACT-PSD
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	SMALL INTERNAL COMBUSTION ENGINES (<= 500 HP)	17.21	DIESEL OIL			Nitrogen Oxides (NOx)	B	TURBOCHARGER AND AFTERCOOLER	3.88	G/B-HP-H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	FIRE PUMP ENGINES (2)	17.21	DIESEL FUEL OIL	300	HP	Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICES, GOOD ENGINE DESIGN, IGNITION TIMING RETARD, TURBOCHARGER, AND LOW-TEMPERATURE AFTERCOOLER	4.89	LB/H	BACT-PSD
OK-0129	CHOUTEAU POWER PLANT	01/23/2009 ACT	EMERGENCY FIRE PUMP (267-HP DIESEL)	17.21	LOW SULFUR DIESEL	267	HP	Nitrogen Oxides (NOx)	N		4.59	LB/H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	EMERGENCY ENGINE 1 THRU 8	17.21	DIESEL	29	HP	Nitrogen Oxides (NOx)	P	PURCHASE OF CERTIFIED ENGINE.	7.5	GR/KW-H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	FIRE PUMP	17.21	DIESEL	500	HP	Nitrogen Oxides (NOx)	P	PURCHASE OF CERTIFIED ENGINE BASED ON NSPS, SUBPART IIII.	4	GR/KW-H	BACT-PSD
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	12/23/2010 ACT	Two emergency diesel firewater pump engines	17.22		250	HP	Nitrogen Oxides (NOx)	P	demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	3	G/HP-H	BACT-PSD
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	AIRCRAFT ARRESTORS	17.22	GASOLINE			Nitrogen Oxides (NOx)	P	GOOD COMBUSTION PRACTICE	5.02	G/B-HP-H	BACT-PSD
ID-0018	LANGLEY GULCH POWER PLANT	06/25/2010 ACT	FIRE PUMP ENGINE	17.21	DIESEL	235	KW	Particulate Matter (PM)	P	TIER 3 ENGINE-BASED, GOOD COMBUSTION PRACTICES (GCP)	0.2	G/KW-H	BACT-PSD
MD-0040	CPV ST CHARLES	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	17.21	DIESEL	300	HP	Particulate Matter (PM)	N		0.15	G/HP-H	BACT-PSD
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	10/10/2012 ACT	Fire Pump	17.21	Diesel	0		Nitrogen Oxides (NOx)	N		2.6	G/B-HP-H	OTHER CASE-BY-CASE
MD-0040	CPV ST CHARLES	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY GENERATOR	17.21	DIESEL			Particulate Matter (PM)	N		0.15	G/HP-H	BACT-PSD
AZ-0051	DRAKE	04/12/2006 ACT	EMERGENCY GENERATOR	17.21	FUEL OIL #2	210	KW	Particulate matter, filterable (FPM)	N		0.2	G/KW-H	BACT-PSD
CA-1144	BLYTHE ENERGY PROJECT II	04/25/2007 ACT	FIRE PUMP	17.21	DIESEL	303	HP	Particulate matter, filterable < 10 µ (FPM10)	N		0.1	LB/H	BACT-PSD
LA-0192	CRESCENT CITY POWER	06/06/2005 ACT	DIESEL FIRED WATER PUMP	17.21				Particulate matter, filterable < 10 µ (FPM10)	P	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	0.14	LB/H	BACT-PSD
LA-0224	ARSENAL HILL POWER PLANT	03/20/2008 ACT	DFP DIESEL FIRE PUMP	17.21	DIESEL	310	HP	Particulate matter, filterable < 10 µ (FPM10)	N	USE OF LOW-SULFUR FUELS, LIMITING OPERATING HOURS AND PROPER ENGINE MAINTENANCE	0.68	LB/H	BACT-PSD
LA-0251	FLOPAM INC. FACILITY	04/26/2011 ACT	Small Generator Engine	17.21	diesel	193	hp	Particulate matter, filterable < 10 µ (FPM10)	N		0.01	LB/H	BACT-PSD
LA-0251	FLOPAM INC. FACILITY	04/26/2011 ACT	Fire Pump Engines - 2 units	17.21	diesel	444	hp	Particulate matter, filterable < 10 µ (FPM10)	N		0.01	LB/H	BACT-PSD
MD-0040	CPV ST CHARLES	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	17.21	DIESEL	300	HP	Particulate matter, filterable < 10 µ (FPM10)	N		0.15	GR-HP-H	BACT-PSD
MD-0040	CPV ST CHARLES	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY GENERATOR	17.21	DIESEL			Particulate matter, filterable < 10 µ (FPM10)	N		0.15	G/HP-H	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/2005 ACT	IC ENGINE, EMERGENCY GENERATOR	17.21	DIESEL FUEL	11.4	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	N		1.14	LB/H	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/2005 ACT	IC ENGINE, EMERGENCY FIREWATER PUMP	17.21	DIESEL FUEL	11.4	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	N		1.14	LB/H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	FIRE PUMP ENGINES (2)	17.21	DIESEL FUEL OIL	300	HP	Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION PRACTICES AND GOOD ENGINE DESIGN	0.27	LB/H	BACT-PSD
OK-0111	MUSKOGEE PORCELAIN FLOOR TILE PLT	10/14/2005 ACT	EMERGENCY GENERATORS	17.21				Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION	0.0022	LB/HP-H	BACT-PSD
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	03/11/2010 ACT	EMERGENCY FIREWATER PUMP ENGINE	17.21	DIESEL	135	KW	Particulate matter, total (TPM)	N	OPERATIONAL RESTRICTION OF 50 HR/YR, OPERATE AS REQUIRED FOR FIRE SAFETY TESTING	0.2	G/KW-H	BACT-PSD
CA-1192	AVENAL ENERGY PROJECT	06/21/2011 ACT	EMERGENCY FIREWATER PUMP ENGINE	17.21	DIESEL	288	HP	Particulate matter, total (TPM)	P	USE ULTRA LOW SULFUR FUELNOT TO EXCEED 15 PPMVD FUEL SULFUR, OPERATIONAL LIMIT OF 50 HRS/YR	0		BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	EMERGENCY IC ENGINE	17.21	DIESEL	182	HP	Particulate matter, total (TPM)	P	USE ULTRA LOW SULFUR FUEL	0.2	G/KW-H	BACT-PSD
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	12/23/2010 ACT	Emergency Diesel Fire Pump, One 600 HP	17.21	ULSD	0		Particulate matter, total (TPM)	N		0.15	G/HP-H	BACT-PSD
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	12/23/2010 ACT	250 Kw Emergency Generator	17.21	ULSD	0		Particulate matter, total (TPM)	P	Use of inherently clean ultra low sulfur distillate (ULSD) fuel oil and GCP & demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	0.2	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Fire Pump	17.21	diesel fuel	14	GAL/H	Particulate matter, total (TPM)	P	good combustion practices	0.2	G/KW-H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009 ACT	FIRE BOOSTER PUMP	17.21	TRA LOW SULFUR DIES	40	KW	Particulate matter, total (TPM)	P	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.4	G/KW-H	BACT-PSD
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	12/23/2010 ACT	Two emergency diesel firewater pump engines	17.22		250	HP	Particulate matter, total (TPM)	P	demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII	0.15	G/HP-H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009 ACT	FLUE GAS DESULFURIZATION QUENCH PUMP	17.23	TRA LOW SULFUR DIES	305	KW	Particulate matter, total (TPM)	P	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.2	G/KW-H	BACT-PSD
CA-1192	AVENAL ENERGY PROJECT	06/21/2011 ACT	EMERGENCY FIREWATER PUMP ENGINE	17.21	DIESEL	288	HP	Particulate matter, total < 10 µ (TPM10)	P	USE ULTRA LOW SULFUR FUEL NOT TO EXCEED 15 PPMVD FUEL SULFUR, OPERATIONAL LIMIT OF 50 HRS/YR	0		BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	EMERGENCY IC ENGINE	17.21	DIESEL	182	HP	Particulate matter, total < 10 µ (TPM10)	P	USE ULTRA LOW SULFUR FUEL	0.2	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Fire Pump	17.21	diesel fuel	14	GAL/H	Particulate matter, total < 10 µ (TPM10)	P	good combustion practices	0.2	G/KW-H	BACT-PSD
LA-0204	PLAQUEMINE PVC PLANT	02/27/2009 ACT	SMALL EMERGENCY ENGINES	17.21	DIESEL			Particulate matter, total < 10 µ (TPM10)	P	GOOD COMBUSTION PRACTICES AND GASEOUS FUEL BURNING	0.31	LB/MMBTU	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	08/16/2011 ACT	EMERGENCY FIRE PUMP	17.21	DIESEL	350	HP	Particulate matter, total < 10 µ (TPM10)	P	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	0.15	G/HP-H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009 ACT	FIRE BOOSTER PUMP	17.21	TRA LOW SULFUR DIES	40	KW	Particulate matter, total < 10 µ (TPM10)	P	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.31	LB/MMBTU	BACT-PSD
OK-0129	CHOUTEAU POWER PLANT	01/23/2009 ACT	EMERGENCY FIRE PUMP (267-HP DIESEL)	17.21	LOW SULFUR DIESEL	267	HP	Particulate matter, total < 10 µ (TPM10)	N		0.24	LB/H	BACT-PSD
VA-0319	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	08/27/2012 ACT	FIRE WATER PUMP	17.21	diesel (ultra low sulfur)	1.86	MMBTU/H	Particulate matter, total < 10 µ (TPM10)	P	Clean burning ULSD fuel and good combusion practices	0.15	G/HP-H	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009 ACT	FLUE GAS DESULFURIZATION QUENCH PUMP	17.23	TRA LOW SULFUR DIES	305	KW	Particulate matter, total < 10 µ (TPM10)	P	ENGINE DESIGN AND OPERATION. 15 PPM SULFUR FUEL.	0.31	LB/MMBTU	BACT-PSD
CA-1191	VICTORVILLE 2 HYBRID POWER PROJECT	03/11/2010 ACT	EMERGENCY FIREWATER PUMP ENGINE	17.21	DIESEL	135	KW	Particulate matter, total < 2.5 µ (TPM2.5)	N	OPERATIONAL RESTRICTION OF 50 HR/YR, OPERATE AS REQUIRED FOR FIRE SAFETY TESTING	0.2	G/KW-H	BACT-PSD
CA-1212	PALMDALE HYBRID POWER PROJECT	10/18/2011 ACT	EMERGENCY IC ENGINE	17.21	DIESEL	182	HP	Particulate matter, total < 2.5 µ (TPM2.5)	P	USE ULTRA LOW SULFUR FUEL	0.2	G/KW-H	BACT-PSD
IA-0105	IOWA FERTILIZER COMPANY	10/26/2012 ACT	Fire Pump	17.21	diesel fuel	14	GAL/H	Particulate matter, total < 2.5 µ (TPM2.5)	P	good combustion practices	0.2	G/KW-H	BACT-PSD
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	08/16/2011 ACT	EMERGENCY FIRE PUMP	17.21	DIESEL	350	HP	Particulate matter, total < 2.5 µ (TPM2.5)	P	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	0.15	G/HP-H	BACT-PSD
VA-0319	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	08/27/2012 ACT	FIRE WATER PUMP	17.21	diesel (ultra low sulfur)	1.86	MMBTU/H	Particulate matter, total < 2.5 µ (TPM2.5)	P	Clean burning ULSD fuel and good combustion practices.	0.15	G/HP-H	BACT-PSD
MD-0040	CPV ST CHARLES	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	17.21	DIESEL	300	HP	Particulate matter, filterable < 2.5 µ (FPM2.5)	N		0.15	G/HP-H	LAER
MD-0040	CPV ST CHARLES	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY GENERATOR	17.21	DIESEL			Particulate matter, filterable < 2.5 µ (FPM2.5)	N		0.15	G/HP-H	LAER
NH-0018	BERLIN BIOPOWER	07/26/2010 ACT	EU03 FIRE PUMP ENGINE	17.21	DIESEL FUEL	2.27	MMBTU/H	Particulate matter, filterable (FPM)	N		0.3	E-5 LB/MMBTU	MACT
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	SMALL INTERNAL COMBUSTION ENGINES (<= 500 HP)	17.21	DIESEL OIL			Particulate matter, filterable < 10 µ (FPM10)	B	TURBOCHARGER AND AFTERCOOLER	0.14	G/B-HP-H	OTHER CASE-BY-CASE
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	10/10/2012 ACT	Fire Pump	17.21	Diesel	0		Particulate matter, total < 10 µ (TPM10)	N		0.09	G/B-HP-H	OTHER CASE-BY-CASE
AK-0081	POINT THOMSON PRODUCTION FACILITY	06/12/2013 ACT	Combustion	17.21	ULSD	493	hp	Particulate matter, total < 2.5 µ (TPM2.5)	P	Good combustion and operating practices.	0.2	G/KW-H	OTHER CASE-BY-CASE
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	10/10/2012 ACT	Fire Pump	17.21	Diesel	0		Particulate matter, total < 2.5 µ (TPM2.5)	N		0.09	G/B-HP-H	OTHER CASE-BY-CASE
OK-0110	MUSKOGEE PORCELAIN FLOOR TILE PLT	10/21/2005 ACT	EMERGENCY GENERATORS	17.21				Particulate matter, filterable < 10 µ (FPM10)	P	GOOD COMBUSTION	0.0022	LB/HP-H	
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	12/23/2010 ACT	250 Kw Emergency Generator	17.21	ULSD	0		Sulfur Dioxide (SO2)	N		0.0015	% SULFUR	BACT-PSD
LA-0192	CRESCENT CITY POWER	06/06/2005 ACT	DIESEL FIRED WATER PUMP	17.21				Sulfur Dioxide (SO2)	P	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	0.61	LB/H	BACT-PSD
LA-0224	ARSENAL HILL POWER PLANT	03/20/2008 ACT	DFP DIESEL FIRE PUMP	17.21	DIESEL	310	HP	Sulfur Dioxide (SO2)	N	USE OF LOW-SULFUR FUELS, LIMITING OPERATING HOURS AND PROPER ENGINE MAINTENANCE	0.64	LB/H	BACT-PSD
MD-0040	CPV ST CHARLES	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	17.21	DIESEL	300	HP	Sulfur Dioxide (SO2)	P		0		BACT-PSD
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	09/07/2007 ACT	DIESEL FIRE WATER PUMPS (<500 HP)	17.21				Sulfur Dioxide (SO2)	P	LIMITED SULFUR IN FUEL; LIMITED HOURS	0.05	%	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/2005 ACT	IC ENGINE, EMERGENCY GENERATOR	17.21	DIESEL FUEL	11.4	MMBTU/H	Sulfur Dioxide (SO2)	N		0.58	LB/H	BACT-PSD
NC-0101	FORSYTH ENERGY PLANT	09/29/2005 ACT	IC ENGINE, EMERGENCY FIREWATER PUMP	17.21	DIESEL FUEL	11.4	MMBTU/H	Sulfur Dioxide (SO2)	N		0.58	LB/H	BACT-PSD
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	SMALL INTERNAL COMBUSTION ENGINES (<= 500 HP)	17.21	DIESEL OIL			Sulfur Dioxide (SO2)	P	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.05%	0.99	G/B-HP-H	BACT-PSD
OK-0129	CHOUTEAU POWER PLANT	01/23/2009 ACT	EMERGENCY FIRE PUMP (267-HP DIESEL)	17.21	LOW SULFUR DIESEL	267	HP	Sulfur Dioxide (SO2)	N	LOW SULFUR DIESEL	0.11	LB/H	BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	EMERGENCY ENGINE 1 THRU 8	17.21	DIESEL	29	HP	Sulfur Dioxide (SO2)	P	LOW SULFUR DIESEL. MAXIMUM OF 100 HOURS PER YEAR RUNNING TIME FOR MAINTENANCE AND TESTING.	0		BACT-PSD
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	FIRE PUMP	17.21	DIESEL	500	HP	Sulfur Dioxide (SO2)	P	USE OF LOW SULFUR FUEL DIESEL, SULFUR CONTENT LESS THAN 0.0015 PERCENT. OPERATING HOURS LESS THAN 100 HOURS PER YEAR FOR MAINTENACE AND TESTING.	0		BACT-PSD
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	12/23/2010 ACT	Two emergency diesel firewater pump engines	17.22		250	HP	Sulfur Dioxide (SO2)	N		0.0015	% SULFUR	BACT-PSD
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	AIRCRAFT ARRESTORS	17.22	GASOLINE			Sulfur Dioxide (SO2)	P	USE OF LOW-SULFUR GASOLINE	0.28	G/B-HP-H	BACT-PSD

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-23. Summary of Identified NO_X Control Technology - Medical Waste Incinerators (RBLC 21.300)

Pollutant	Control Technology Used	Number of RBLC Entries (1 Total)
NO_X	SCR	-
	SNCR	-
	Multiple Chambers	1

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015. SCR and SNCR have been added for consideration.

Table A-24. Summary of Identified $PM_{2.5}$ Control Technology - Medical Waste Incinerators (RBLC 21.300)

Pollutant	Control Technology Used	Number of RBLC Entries (1 Total)
$PM_{2.5}$	Multiple Chambers	1

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-25. Summary of Identified SO_2 Control Technology - Medical Waste Incinerators (RBLC 21.300)

Pollutant	Control Technology Used	Number of RBLC Entries (Total)
SO_2	Natural Gas as Fuel	1
	ULSD	-

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015. ULSD has been added for consideration.

Table A-26. RBLC Control Technology Determinations for Medical Waste Incinerators (RBLC 21.300)

RBLC ID	FACILITY NAME	PERMIT SSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPU T UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	MEDICAL WASTE INCINERATOR	21.3	NATURAL GAS			Nitrogen Oxides (NOx)	P	MULTIPLE-CHAMBER DESIGN AND TEMPERATURE CONTROL	0.09	LB/H	Other Case-by-Case
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	MEDICAL WASTE INCINERATOR	21.3	NATURAL GAS			Particulate matter, filterable < 10 µ (FPM10)	P	MULTIPLE-CHAMBER DESIGN AND TEMPERATURE CONTROL	0.04	LB/H	Other Case-by-Case
NV-0047	NELLIS AIR FORCE BASE	02/26/2008 ACT	MEDICAL WASTE INCINERATOR	21.3	NATURAL GAS			Sulfur Oxides (SOx)	P	USE OF NATURAL GAS AS THE FUEL	0.05	LB/H	BACT-PSD

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-27. Summary of Identified PM Control Technology - Material Handling

Pollutant	Control Technology Used	Number of Coal Handling (RBLC ID 90.011) Entries (85 Total)	Number of Lime/Limestone Handling (RBLC ID 90.019) Entries (71 Total)	Number of Ash Handling (RBLC ID 99.120) Entries (74 Total)
$PM_{2.5}$	None	50	9	6
	Baghouse (Fabric Filter)	49	32	32
	Enclosure	15	15	16
	Suppressant	12	1	8
	Wind Screens	4	1	-
	Good Operating Practices	3	2	2
	Dust Collector	1	7	2
	Water Fogging	1	-	-
	Vent	-	-	4
	Negative Pressure Vent	-	-	1

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-28. RBLC Control Technology Determinations for Lime and Limestone Handling (RBLC 90.019)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
AL-0220	CHEMICAL LIME COMPANY - O"NEAL PLANT	03/23/2005 ACT	RAW MATERIALS HANDLING	90.019				Particulate Matter (PM)	N		0.005	GR/DSCF	BACT-PSD
AL-0220	CHEMICAL LIME COMPANY - O"NEAL PLANT	03/23/2005 ACT	KILN 1 & COOLER	90.019	COAL	1500	T/D	Particulate Matter (PM)	A	BAGHOUSE	0.014	GR/DSCF	BACT-PSD
AL-0220	CHEMICAL LIME COMPANY - O"NEAL PLANT	03/23/2005 ACT	KILN 2 & COOLER	90.019	COAL	1500	T/D	Particulate Matter (PM)	A	BAGHOUSE	0.01	GR/DSCF	BACT-PSD
AL-0220	CHEMICAL LIME COMPANY - O"NEAL PLANT	03/23/2005 ACT	KILN DUST BINS & REJECT LIME BINS	90.019				Particulate Matter (PM)	N		0.005	GR/DSCF	BACT-PSD
AL-0220	CHEMICAL LIME COMPANY - O"NEAL PLANT	03/23/2005 ACT	LIME PRODUCT HANDLING & STORAGE	90.019				Particulate Matter (PM)	N		0.005	GR/DSCF	BACT-PSD
AL-0220	CHEMICAL LIME COMPANY - O"NEAL PLANT	03/23/2005 ACT	LIME PRODUCT LOADOUT (TRUCKS & RAILCARS)	90.019				Particulate Matter (PM)	N		0.005	GR/DSCF	BACT-PSD
AR-0082	ARKANSAS LIME COMPANY	08/30/2005 ACT	LIME DISCHARGE, SN-32Q #3	90.019				Particulate Matter (PM)	A	DUST COLLECTOR	0.01	GR/DSCF	BACT-PSD
CO-0057	COMANCHE STATION	07/05/2005 ACT	LIME HANDLING	90.019				Particulate Matter (PM)	A	SILOS ARE EQUIPPED WITH BAGHOUSES, SLAKERS ARE EQUIPPED WITH SCRUBBERS	0.01	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	#4 LIMESTONE SYSTEM - SILO	90.019		10	T/H	Particulate Matter (PM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	09/19/2008 ACT	LIME SILO	90.019		150	Tons	Particulate Matter (PM)	A	DUST COLLECTOR	0.005	GR/DSCF	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	FLUXANT TRUCK LDOUT & CONVEYING, FUG	90.019		250	T/H	Particulate Matter (PM)	N	COVERED CONVEYORS AND ENCLOSED TRANSFER POINTS. FUGITIVE DUST BMPS.	20	%	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	FLUXANT STORAGE, SRCXX	90.019		250	T/H	Particulate Matter (PM)	A	HIGH EFFICIENCY BAGHOUSE(S) ON STORAGE SILO VENT(S)	0.002	LB/H	BACT-PSD
ND-0021	GASCOYNE GENERATING STATION	06/03/2005 ACT	MATERIALS HANDLING	90.019		100	T/H	Particulate Matter (PM)	A	BAGHOUSES	0.005	GR/DSCF	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	LIME KILN (P50)	90.019	AL / PET C	650	T/D	Particulate Matter (PM)	A	HIGH TEMPERATURE MEMBRANE (PTFE) FABRIC FILTER BAGHOUSE; PREHEATER LIME KILN	5.4	LB/H	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	LIME CRUSHING AND HANDLING (P51)	90.019				Particulate Matter (PM)	A	FABRIC FILTER BAGHOUSE, WITH TOTAL ENCLOSURE OF PROCESS OPERATIONS	0.58	LB/H	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	LIME STORAGE AND HANDLING (P52)	90.019				Particulate Matter (PM)	B	FABRIC FILTER BAGHOUSE, TOTAL ENCLOSURE OF THE PROCESS OPERATIONS	0.56	LB/H	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	SMALL SILO TRUCK LOADING (P53)	90.019				Particulate Matter (PM)	B	FABRIC FILTER BAGHOUSE, TOTAL ENCLOSURE OF THE PROCESS OPERATIONS, USE OF A VACUUM RING FOR TRUCK FILLING	0.06	LB/H	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	LARGE SILO TRUCK LOADING (P54)	90.019				Particulate Matter (PM)	B	FABRIC FILTER BAGHOUSE, TOTAL ENCLOSURE OF THE PROCESS OPERATIONS, USE OF A VACUUM RING FOR TRUCK FILLING	0.04	LB/H	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	LIME FINES STORAGE (FOR ALL KILNS) P56	90.019				Particulate Matter (PM)	B	FABRIC FILTER BAGHOUSE, TOTAL ENCLOSURE OF OPERATIONS	0.17	LB/H	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	OFF SPEC. BIN STORAGE AND HANDLING (P57)	90.019				Particulate Matter (PM)	B	FABRIC FILTER BAGHOUSE, TOTAL ENCLOSURE OF PROCESS OPERATIONS	0.04	LB/H	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	CORE BIN TRUCK LOADING (P58)	90.019				Particulate Matter (PM)	A	FABRIC FILTER BAGHOUSE, TOTAL ENCLOSURE, EXCEPT FOR TRUCK PAD. VACUUM RING FOR TRUCK FILLING	0.06	LB/H	BACT-PSD
WI-0252	SPECIALTY MINERALS INC. - SUPERIOR	07/22/2011 ACT	P10 - LIME SILO	90.019		0		Particulate Matter (PM)	B	PNEUMATIC CONVEYING, TOTAL ENCLOSURE AND BIN VENT FABRIC FILTER.	0.13	LB/H	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	04/26/2006 ACT	LIMESTONE HANDLING	90.019		100	T/H	Particulate Matter (PM)	A	FABRIC FILTERS	0.01	GR/DSCF	BACT-PSD
IN-0139	DUKE ENERGY INDIANA, INC. - EDWARDSPORT GENERAT**	03/01/2010 ACT	LIME AND SODA ASH HANDLING (4 SILOS)	90.019		46	T/H EACH	Particulate matter, filterable (FPM)	A	BIN VENTDUST COLLECTOR	0.019	LB/H *	OTHER CASE-BY-CASE
*IN-0167	MAGNETATION LLC	04/16/2013 ACT	LIMESTONE UNLOADING (TRUCK)	90.019		495	T/H	Particulate matter, filterable (FPM)	P	DEVELOPMENT, MAINTENANCE, AND IMPLEMENTATAION OF A SITE-SPECIFIC FUGITIVE DUST CONTROL PLAN	0.0011	LB/H	BACT-PSD
LA-0239	NUCOR STEEL LOUISIANA	05/24/2010 ACT	COK-112 - Coke Battery 1 FGD Lime Silo Unloading	90.019		21810	t/yr	Particulate matter, filterable (FPM)	A	BACT is selected as collection and control by fabric filters.	0.005	LB/H	BACT-PSD
LA-0239	NUCOR STEEL LOUISIANA	05/24/2010 ACT	COK-212 - Coke Battery 2 FGD Lime Silo Unloading	90.019		21810	t/yr	Particulate matter, filterable (FPM)	A	BACT is selected as collection and control by fabric filters.	0.005	LB/H	BACT-PSD
ND-0024	SPIRITWOOD STATION	09/14/2007 ACT	MATERIALS HANDLING	90.019		60	T/H	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	LIME KILN (P50)	90.019	AL / PET C	650	T/D	Particulate matter, filterable (FPM)	A	HIGH TEMPERATURE MEMBRANE (PTFE) FABRIC FILTER BAGHOUSE; PREHEATER LIME KILN	0.1	LB/T	
AR-0082	ARKANSAS LIME COMPANY	08/30/2005 ACT	LIME STORAGE SILO DUST COLLECTORS, SN-36Q AND SN-37Q	90.019				Particulate matter, filterable < 10 µ (FPM10)	A	DUST COLLECTOR	0.015	GR/DSCF	BACT-PSD
AR-0082	ARKANSAS LIME COMPANY	08/30/2005 ACT	LIME LOADOUT DUST COLLECTOR, SN-38Q AND SN-39Q	90.019				Particulate matter, filterable < 10 µ (FPM10)	A	DUST COLLECTOR	0.015	GR/DSCF	BACT-PSD
AR-0082	ARKANSAS LIME COMPANY	08/30/2005 ACT	LIME KILN, SN-30Q	90.019	E AND NAT	45254	T/YR	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.1	LB/T	BACT-PSD
CO-0055	LAMAR LIGHT & POWER POWER PLANT	02/03/2006 ACT	LIMESTONE HANDLING /PROCESSING/ STORAGE	90.019		30	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	HIGH EFFICIENCY FABRIC FILTER BAGHOUSES	0.045	LB/T	BACT-PSD
CO-0057	COMANCHE STATION	07/05/2005 ACT	LIME HANDLING	90.019				Particulate matter, filterable < 10 µ (FPM10)	A	SILOS ARE EQUIPPED WITH BAGHOUSES AND SLAKERS ARE EQUIPPED WITH SCRUBBERS	0.01	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	#4 LIMESTONE SYSTEM - SILO	90.019		10	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	09/19/2008 ACT	LIME SILO	90.019		150	Tons	Particulate matter, filterable < 10 µ (FPM10)	A	DUST COLLECTOR	0.005	GR/DSCF	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	FLUXANT TRUCK LDOUT & CONVEYING, FUG	90.019		250	T/H	Particulate matter, filterable < 10 µ (FPM10)	N	COVERED CONVEYORS AND ENCLOSED TRANSFER POINTS. FUGITIVE DUST BMPS.	0		BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	FLUXANT STORAGE, SRCXX	90.019		250	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	HIGH EFFICIENCY BAGHOUSE(S) ON STORAGE SILO VENT(S)	0.002	LB/H	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	LIME SILO STORAGES	90.019		0		Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTERS	0.005	GR/DSCF	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	LIMESTONE STORAGE SILOS	90.019		40	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER	0.005	GR/DSCF	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	36-08 FUEL/LIMESTONE DIVERTER TOWER	90.019		1500	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	WET SUPPRESSION, COVERED CONVEYORS, ENCLOSED DROP POINTS, LOWERING TUBES FOR DIVERTING MATERIALS TO STORAGE PILES AND BEST OPERATING PRACTICES ARE BACT FOR MATERIAL HANDLING.	2.59	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	CRUSHED LIMESTONE DAY BINS (2)	90.019		6000	CFM	Particulate matter, filterable < 10 µ (FPM10)	N		0.51	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	COVERED LIMESTONE STOCKOUT PILE-DROP POINT	90.019		1500	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	LOWERING TUBE	2.59	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	LIMESTONE STOCKOUT PILE	90.019		3002	CU YD/YR	Particulate matter, filterable < 10 µ (FPM10)	P	PILE COVERED	32.9	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	INACTIVE LIMESTONE PILE	90.019		378381	CU YD/YR	Particulate matter, filterable < 10 µ (FPM10)	N		823.2	LB/H	BACT-PSD
LA-0221	LITTLE GYPSY GENERATING PLANT	11/30/2007 ACT	LIMESTONE STORAGE PILE	90.019		96000	T/YR	Particulate matter, filterable < 10 µ (FPM10)	P	DUST SUPPRESSION	170.58	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	LIMESTONE STORAGE DOME	90.019		1400	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTERS	0.01	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	LIMESTONE TRANSFER TOWER - CONVEYOR C-9 TO CONVEYOR C-10	90.019		200	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	WIND SCREENS AND DRY FOGGING	0.01	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	LIMESTONE SILO AND CRUSHER	90.019		200	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTERS	0.02	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	LIME SILO	90.019		20	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTERS	0.22	LB/H	BACT-PSD
OH-0321	MARTIN MARIETTA MATERIALS	11/13/2008 ACT	ROTARY LIME KILN	90.019	DKE, NATU	18000	LB/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE WITH 100% CAPTURE EFFICIENCY	37.8	T/YR	BACT-PSD
OH-0321	MARTIN MARIETTA MATERIALS	11/13/2008 ACT	PRODUCT TRANSFER, PROCESSED STONE, CONVEYING AT KILN	90.019		5000000	T/YR	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	1.23	T/YR	BACT-PSD
OH-0321	MARTIN MARIETTA MATERIALS	11/13/2008 ACT	LIME LOAD-OUT, SCREENING, TRANSFER, STORAGE	90.019		300	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSES (2) WHICH SHALL ACHIEVE 99.5% CAPTURE EFFICIENCY	3.32	T/YR	BACT-PSD
OH-0321	MARTIN MARIETTA MATERIALS	11/13/2008 ACT	DUST LOAD-OUT SYSTEM	90.019		100	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE WITH 99.5% CAPTURE EFFICIENCY. MECHANICAL ENCLOSURED FOR CONVEYING EQUIPMENT	8.1	T/YR	BACT-PSD
WI-0252	SPECIALTY MINERALS INC. - SUPERIOR	07/22/2011 ACT	P10 - LIME SILO	90.019		0		Particulate matter, filterable < 2.5 µ (FPM2.5)	B	PNEUMATIC CONVEYING, TOTAL ENCLOSURE, BIN VENT FABRIC FILTER	0.026	LB/H	BACT-PSD
OH-0321	MARTIN MARIETTA MATERIALS	11/13/2008 ACT	STONE CRUSHING AND SCREENING	90.019		1000	T/H	Particulate matter, fugitive	P	BEST AVAILABLE CONTROL MEASURES: MAINTAIN INHERENT MOISTURE AND INCLUDE MANY VIBRATING FEEDERS AND MATERIAL HANDLING PROCESSES WITHIN TUNNEL ENCLOSURES.	9.79	T/YR	BACT-PSD
OH-0321	MARTIN MARIETTA MATERIALS	11/13/2008 ACT	PRODUCT TRANSFER, PROCESSED STONE, CONVEYING AT KILN	90.019		5000000	T/YR	Particulate matter, fugitive	N		1.91	T/YR	BACT-PSD
OH-0321	MARTIN MARIETTA MATERIALS	11/13/2008 ACT	LIME LOAD-OUT, SCREENING, TRANSFER, STORAGE	90.019		300	T/H	Particulate matter, fugitive	N		0.98	T/YR	BACT-PSD
OH-0321	MARTIN MARIETTA MATERIALS	11/13/2008 ACT	DUST LOAD-OUT SYSTEM	90.019		100	T/H	Particulate matter, fugitive	N		0.21	T/YR	BACT-PSD
WI-0250	GRAYMONT (WI) LLC	02/06/2009 ACT	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	90.019	COAL	54	T/H STONE	Particulate matter, fugitive	A	FABRIC FILTER BAGHOUSE	0.46	LB/T	BACT-PSD
IN-0139	DUKE ENERGY INDIANA, INC. - EDWARDSPOR	03/01/2010 ACT	LIME AND SODA ASH HANDLING (4 SILO	90.019		46	T/H EACH	Particulate matter, filterable (FPM)	A	BIN VENTDUST COLLECTOR	0.019	LB/H *	OTHER CASE-BY-CASE

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-29. RBLC Control Technology Determinations for Coal Handling (RBLC 99.011)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
AL-0220	CHEMICAL LIME COMPANY - O"NEAL PLANT	03/23/2005 ACT	FUEL HANDLING & STORAGE	90.011	COAL			Particulate Matter (PM)	N		0.005	GR/DSCF	BACT-PSD
CO-0057	COMANCHE STATION	07/05/2005 ACT	COAL HANDLING AND STORAGE	90.011				Particulate Matter (PM)	B	CONTROLS INCLUDE USE OF WATER SPRAYS, LOWERING WELL, DUST SUPPRESSANTS, ENCLOSURES AND BAGHOUSES WHERE FEASIBLE.	0.01	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	COAL SYSTEM - BUNKER #3 SILO	90.011		27.4	LB/H	Particulate Matter (PM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	COAL PILE	90.011		50565	tons	Particulate Matter (PM)	P	DUST SUPPRESSANT	95	%	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	COAL PILE - TRAFFIC	90.011		50565	tons	Particulate Matter (PM)	P	DUST SUPPRESSANT	80	%	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	COAL RECEIVING AND HANDLING, S12 (07-A-958P)	90.011		200	T/H	Particulate Matter (PM)	A	BAGHOUSE WATER FOGGING	0.005	GR/DSCF	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	GASIFIER COAL FEED BINS, S14 (07-A-959P)	90.011		15	TONS	Particulate Matter (PM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	COAL STORAGE SILOS, S15 (07-A-960P)	90.011		5000	TONS	Particulate Matter (PM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	COAL STORAGE RECLAIM SILO, S16 (07-A-961P)	90.011		5000	TONS	Particulate Matter (PM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	COAL/PETCOKE RAILCAR UNLOADING & STORAGE, SRC01-SRC07	90.011		5000	T/H	Particulate Matter (PM)	B	ENCLOSED RAILCAR UNLOADING AT NEGATIVE PRESSURE. COVERED CONVEYORS AND ENCLOSED TRANSFER POINTS. STORAGE IN EUROSILO OR EQUIVALENT. HIGH EFFICIENCY BAGHOUSES (RAILCAR UNLOADING, CONVEYORS, STORAGE SILO VENTS).	0.09	LB/H	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	COAL/PETCOKE RECLAIM TO ROD MILL, SRC08-SRC12	90.011		105	T/H	Particulate Matter (PM)	B	COVERED CONVEYORS WITH ENCLOSED TRANSFER POINTS. HIGH EFFICIENCY BAGHOUSES.	0.002	LB/H	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	COAL STOCKPILE	90.011		3000	T/H	Particulate Matter (PM)	P	WET SUPPRESSION, DUST SUPPRESSENT LOWERING WELL AND COMPACTION.	10	OPACITY	BACT-PSD
MN-0061	ERIE NUGGET	06/26/2005 ACT	COAL PULVERIZER #1	90.011	ATURAL G	36	MMBTU/H	Particulate Matter (PM)	A	FF	0.01	GR/DSCF	BACT-PSD
MN-0061	ERIE NUGGET	06/26/2005 ACT	COAL PULVERIZER #2	90.011	ATURAL G	9	MMBTU/H	Particulate Matter (PM)	A	FF	0.01	GR/DSCF	BACT-PSD
MN-0061	ERIE NUGGET	06/26/2005 ACT	COAL & FLUX UNLOADING	90.011	NA	4000000	DSCF	Particulate Matter (PM)	A	FF	0.005	GR/DSCF	BACT-PSD
ND-0021	GASCOYNE GENERATING STATION	06/03/2005 ACT	COAL HANDLING	90.011		400	T/H	Particulate Matter (PM)	A	BAGHOUSES	0.005	GR/DSCF	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/08/2009 ACT	COAL CONVEYING, HANDLING, AND CRUSHING	90.011		5553840	T/YR	Particulate Matter (PM)	N		77.6	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	CRUSHER HOUSE, TRANSFER TOWER 2, SILOS A-D	90.011				Particulate Matter (PM)	N		0.76	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	ACTIVE STORAGE A-B	90.011				Particulate Matter (PM)	N		3.24	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	INACITVE STORAGE PILE	90.011				Particulate Matter (PM)	N		18.4	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	EMERGENCY PILE	90.011				Particulate Matter (PM)	N		0.42	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	TRANSFER TOWER 31	90.011				Particulate Matter (PM)	N		0.91	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	UNLOADING CONVEYOR	90.011				Particulate Matter (PM)	N		0.42	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	RAILCAR UNLOADER	90.011				Particulate Matter (PM)	N		1.15	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LIMESTONE RAIL	90.011				Particulate Matter (PM)	N		0.6	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LIMESTONE STORAGE PILE	90.011				Particulate Matter (PM)	N		0.42	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FLY ASH TRUCK LOADING	90.011				Particulate Matter (PM)	N		3.38	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FLY ASH BAG LOADING	90.011				Particulate Matter (PM)	N		0.11	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	SLUDGE CONVEYOR	90.011				Particulate Matter (PM)	N		0.03	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	SLUDGE STACKOUT	90.011				Particulate Matter (PM)	N		0.34	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LANDFILL	90.011				Particulate Matter (PM)	N		26.2	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FUEL HANDLING LIGNITE MINE	90.011				Particulate Matter (PM)	N		0.5	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FUEL HANDLING OVERLAND CONVEYOR	90.011				Particulate Matter (PM)	N		4.3	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	TRANSFER TOWER 4	90.011				Particulate Matter (PM)	N		0.25	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	TRANSFER TOWER 1	90.011				Particulate Matter (PM)	N		1.51	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	ACTIVE STORAGE (3)	90.011				Particulate Matter (PM)	N		1.01	LB/H	BACT-PSD
WI-0233	CLM - SUPERIOR	08/16/2006 ACT	COAL (SOLID FUEL) STORAGE AND HANDLING (P55)	90.011				Particulate Matter (PM)	B	FABRIC FILTER BAGHOUSE, TOTAL ENCLOSURE OF THE PROCESS OPERATIONS,	0.04	LB/H	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	04/26/2006 ACT	COAL HANDLING	90.011		300	T/H	Particulate Matter (PM)	A	FABRIC FILTERS	0.01	GR/DSCF	BACT-PSD
IN-0119	AUBURN NUGGET	05/31/2005 ACT	COAL DRYERS	90.011	ATURAL G	33	T (COAL)/H	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.01	GR/DSCF	BACT-PSD
IN-0119	AUBURN NUGGET	05/31/2005 ACT	COAL CAR UNLOADING	90.011	NA	165	T/H	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.0052	GR/DSCF	BACT-PSD
ND-0024	SPIRITWOOD STATION	09/14/2007 ACT	COAL HANDLING	90.011		85.3	T/H	Particulate matter, filterable (FPM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
AR-0082	ARKANSAS LIME COMPANY	08/30/2005 ACT	COAL/COKE BIN VENT, SN-33Q #3	90.011				Particulate matter, filterable < 10 µ (FPM10)	A	DUST COLLECTOR	0.015	GR/DSCF	BACT-PSD
CO-0055	LAMAR LIGHT & POWER POWER PLANT	02/03/2006 ACT	COAL HANDLING AND PREPARATION	90.011		150	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	HIGH EFFICIENCY FABRIC FILTER BAGHOUSES	0.02	LB/T	BACT-PSD
CO-0057	COMANCHE STATION	07/05/2005 ACT	COAL HANDLING AND STORAGE	90.011				Particulate matter, filterable < 10 µ (FPM10)	B	CONTROL INCLUDES WATER SPRAYS, LOWER WELL, DUST SUPPRESSANT, ENCLOSURES AND BAGHOUSES WHERE FEASIBLE.	0.01	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	COAL SYSTEM - BUNKER #3 SILO	90.011		27.4	LB/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	COAL PILE	90.011		50565	tons	Particulate matter, filterable < 10 µ (FPM10)	P	DUST SUPPRESSANT	95	%	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	COAL PILE - TRAFFIC	90.011		50565	tons	Particulate matter, filterable < 10 µ (FPM10)	P	DUST SUPPRESSANT	80	%	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	COAL RECEIVING AND HANDLING, S12 (07-A-958P)	90.011		200	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE AND WATER FOGGING	0.005	GR/DSCF	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	GASIFIER COAL FEED BINS, S14 (07-A-959P)	90.011		15	TONS	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOSUE	0.005	GR/DSCF	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	COAL STORAGE SILOS, S15 (07-A-960P)	90.011		5000	TONS	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	COAL STORAGE RECLAIM SILO, S16 (07-A-961P)	90.011		5000	TONS	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	COAL/PETCOKE RAILCAR UNLOADING & STORAGE, SRC01-SRC07	90.011		5000	T/H	Particulate matter, filterable < 10 µ (FPM10)	B	ENCLOSED RAILCAR UNLOADING AT NEGATIVE PRESSURE. COVERED CONVEYORS AND ENCLOSED TRANSFER POINTS. STORAGE IN EUROSILO OR EQUIVALENT. HIGH EFFICIENCY BAGHOUSES (RAILCAR UNLOADING, CONVEYORS, STORAGE SILO VENTS).	0.04	LB/H	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	02/10/2009 ACT	COAL/PETCOKE RECLAIM TO ROD MILL, SRC08-SRC12	90.011		105	T/H	Particulate matter, filterable < 10 µ (FPM10)	B	COVERED CONVEYORS WITH ENCLOSED TRANSFER POINTS. HIGH EFFICIENCY BAGHOUSES.	0.001	LB/H	BACT-PSD
IN-0118	IRON DYNAMICS, INC. (IDI)	04/13/2005 ACT	COAL DRYER	90.011		25	mmbtu/h	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.01	GR/DSCF	BACT-PSD
IN-0119	AUBURN NUGGET	05/31/2005 ACT	COAL DRYERS	90.011	ATURAL G	33	T (COAL)/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.015	GR/DSCF	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	COAL CRUSHING AND SILO STORAGE	90.011		0		Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER	0.005	GR/DSCF	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	31-08 FUEL/LIMESTONE ROTARY PLOW DROP POINTS	90.011		750	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	WET SUPPRESSION, COVERED CONVEYORS, ENCLOSED DROP POINTS, LOWERING TUBES FOR DIVERTING MATERIALS TO STORAGE PILES AND BEST OPERATING PRACTICES ARE BACT FOR MATERIAL HANDLING.	0.26	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	32-08 COAL STOCKOUT PILE	90.011				Particulate matter, filterable < 10 µ (FPM10)	P	WET SUPPRESSION, COVERED CONVEYORS, ENCLOSED DROP POINTS, LOWERING TUBES FOR DIVERTING MATERIALS TO STORAGE PILES AND BEST OPERATING PRACTICES ARE BACT FOR MATERIAL HANDLING.	102	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	CAR DUMP	90.011		3000	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	ENCLOSED SYSTEM	0.9	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	33-08 COAL STOCKOUT PILE DROP POINT	90.011		1500	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	WET SUPPRESSION, COVERED CONVEYORS, ENCLOSED DROP POINTS, LOWERING TUBES FOR DIVERTING MATERIALS TO STORAGE PILES AND BEST OPERATING PRACTICES ARE BACT FOR MATERIAL HANDLING.	0.69	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	FUEL STOCKOUT PILE DROP POINT	90.011		1500	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	LOWERING TUBE	0.69	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	TRANSFER POINT - EMERGENCY PILE MATERIAL HANDLING	90.011		1200	T/H	Particulate matter, filterable < 10 µ (FPM10)	B	BEST OPERATING PRACTICES AND TELESCOPIC CHUTES	0.8	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	MATERIAL HANDLING - OUTSIDE CONVEYORS	90.011		1800	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	WIND SCREENS	1.88	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	TRANSFER POINTS - BARGE UNLOADER, UNLOADING HOPPER TO CONVEYOR C-1, CONVEYOR C-1 TO CONVEYOR C-2	90.011		1200	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	WIND SCREENS AND DRY FOGGING	0.13	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	TRANSFER HOUSE 1 - CONVEYOR C-2 TO CONVEYOR C-3 OR C-4	90.011		1200	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	WIND SCREENS AND DRY FOGGING	0.06	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	FUEL STORAGE DOME	90.011		1600	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTERS	0.01	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	FUEL CRUSHER HOUSE	90.011		400	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTERS	0.04	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	FUEL SILOS	90.011		400	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTERS	0.002	LB/H	BACT-PSD
MN-0061	ERIE NUGGET	06/26/2005 ACT	COAL PULVERIZER #1	90.011	ATURAL G	36	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	FF	0.015	GR/DSCF	BACT-PSD
MN-0061	ERIE NUGGET	06/26/2005 ACT	COAL PULVERIZER #2	90.011	ATURAL G	9	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	FF	0.015	GR/DSCF	BACT-PSD
MN-0061	ERIE NUGGET	06/26/2005 ACT	COAL & FLUX UNLOADING	90.011	NA	4000000	DSCF	Particulate matter, filterable < 10 µ (FPM10)	A	FF	0.005	GR/DSCF	BACT-PSD
NV-0036	TS POWER PLANT	05/05/2005 ACT	COAL HANDLING OPERATIONS	90.011				Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER DUST COLLECITON	0.01	GR/DSCF	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/08/2009 ACT	COAL CONVEYING, HANDLING, AND CRUSHING	90.011		5553840	T/YR	Particulate matter, filterable < 10 µ (FPM10)	B	BAGHOUSE WITH OPTION OF ENCLOSURES, FOGGING, WET SUPPRESSION	9	T/YR	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	COAL AND BIOMASS SILOS (8)	90.011		1000	T/H	Particulate matter, filterable < 10 µ (FPM10)	B	PULSE JET BAGHOUSE WITH BAG LEAK DETECTION SYSTEM. SILOS AND TRANSFER POINTS TOTALLY ENCLOSED.	0.9	LB/H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	COAL AND BIOMASS CONVERYORS/ TRANSFER TOWERS (5)	90.011		3500	T/H	Particulate matter, filterable < 10 µ (FPM10)	B	BAGHOUSE AND DUST COLLECTOR. TOTALLY ENCLOSED COAL TRANSFER TOWERS AND TRANSFER POINTS.	0.9	LB/H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	COAL AND BIOMASS RECEIVING BUILDING	90.011				Particulate matter, filterable < 10 µ (FPM10)	B	BAGHOUSE AND DUST COLLECTOR. TOTALLY ENCLOSED COAL AND BIOMASS UNLOADING AND CONVEYORS FROM BUILDING, INCLUDING ALL TRANSFER POINTS.	0.12	LB/H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	COAL AND BIOMASS CRUSHER HOUSES (2)	90.011		4000	T/H	Particulate matter, filterable < 10 µ (FPM10)	B	BAGHOUSE WITH DUST COLLECTOR. TOTALLY ENCLOSED CRUSHER HOUSES INCLUDING ALL TRANSFER POINTS, INLET AND EXIT CONVERYORS.	1.2	LB/H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	COAL OR BIOMASS DRYING LINES (10)	90.011	ATURAL G	31	MMBTU/H	Particulate matter, filterable < 10 µ (FPM10)	A	PULSE JET BAGHOUSE	0.6	LB/H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	COAL OR BIOMASS MILLING LINES BUNKER (10)	90.011	COAL	200	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	PULSE JET BAGHOUSE	0.43	LB/H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	COAL OR BIOMASS MILLING LINES FILLING VESSELS (10)	90.011	COAL	200	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	PULSE JET BAGHOUSE	0.07	LB/H	BACT-PSD
OK-0118	HUGO GENERATING STA	02/09/2007 ACT	MATERIAL HANDLING	90.011				Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER BAGHOUSE	0.01	GR/DSCF	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	CRUSHER HOUSE, TRANSFER TOWER 2, SILOS A-D	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.36	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	ACTIVE STORAGE A-B	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		1.56	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	INACITVE STORAGE PILE	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		9.02	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	EMERGENCY PILE	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.21	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	TRANSFER TOWER 31	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.43	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	UNLOADING CONVEYOR	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.2	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	RAILCAR UNLOADER	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.54	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	BAGHOUSE STACK (2)	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.63	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LIMESTONE RAIL	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.3	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LIMESTONE BAGHOUSE STACK	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		1.29	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LIMSETONE CONVEYOR	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.77	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LIMESTONE RECLAIM BAGHOUSE STACK	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.51	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LIMESTONE TOWER BAGHOUSE STACK	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		1.71	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LIMESTONE SILOS BAGHOUSE STACK	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.61	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LIMESTONE STORAGE PILE	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.21	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FLY ASH TRUCK LOADING	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		1.65	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FLY ASH BAG LOADING	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.05	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FLY ASH STORAGE	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		1.15	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	WET SCRUBBER STACK	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.17	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	SLUDGE CONVEYOR	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.02	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	SLUDGE STACKOUT	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.17	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	LANDFILL	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		13.1	T/YR	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	COOLING TOWER	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		5.78	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FUEL HANDLING LIGNITE MINE	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.24	LB/H	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FUEL HANDLING OVERLAND CONVEYOR	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		2.04	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	TRANSFER TOWER 4	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.12	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	TRANSFER TOWER 1	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.72	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	ACTIVE STORAGE (3)	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		0.48	LB/H	BACT-PSD
TX-0507	NRG COAL HANDLING PLANT	04/13/2006 ACT	FLY ASH SILO BAGHOUSE STACK (2)	90.011				Particulate matter, filterable < 10 µ (FPM10)	N		1.59	LB/H	BACT-PSD
WI-0234	STORA ENSO - BIRON MILL	03/31/2006 ACT	COAL SILO	90.011				Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.1	LB/H	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	COAL STORAGE PILES	90.011		5500	T/H	Particulate matter, fugitive	P	3-SIDED WINDSCREEN BARRIER. REDUCED DROP HEIGHTS. USE OF CHEMICAL STABILIZATION DUST SUPPRESSANTS AND/OR WATERING TO REDUCE ANY VISIBLE EMISSIONS.	12.3	T/YR	BACT-PSD
OH-0321	MARTIN MARIETTA MATERIALS	11/13/2008 ACT	COAL AND COKE MATERIAL HANDLING	90.011		78840	T/YR	Particulate matter, fugitive	P	BUILDING ENCLOSURE AND HIGH MOISTURE CONTENT COAL AND COKE >5%	0.95	T/YR	BACT-PSD
IA-0099	POWER PLANT	08/17/2011 ACT	Coal System - Bunker #3 Silo	90.011		27.4	T/H	Particulate matter, total (TPM)	A	baghouse	0.005	GR/DSCF	BACT-PSD
IA-0099	POWER PLANT	08/17/2011 ACT	Coal System - Bunker #3 Silo	90.011		27.4	T/H	Particulate matter, total < 10 µ (TPM10)	A	baghouse	0.005	GR/DSCF	BACT-PSD
IN-0139	DUKE ENERGY INDIANA, INC. - EDWARDSPORT GENERAT**	03/01/2010 ACT	COAL HANDLING AND TRANSFERRING	90.011		12000	T/H OF COAL	Particulate matter, filterable (FPM)	A	BAGHOUSE/BIN VENT COLLECTOR INSERTABLE DUST COLLECTOR	0.003	GR/DSCF	OTHER CASE-BY-CASE

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Table A-30. RBLC Control Technology Determinations for Ash Handling (RBLC 99.120)

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
CO-0057	COMANCHE STATION	07/05/2005 ACT	RECYCLE ASH HANDLING	99.12				Particulate Matter (PM)	A	RECYCLE ASH MIXERS ARE EQUIPPED WITH SCRUBBERS, RECYCLE ASH SILOS ARE EQUIPPED WITH BAGHOUSES	0.01	GR/DSCF	
CO-0057	COMANCHE STATION	07/05/2005 ACT	FLY ASH/ FGD WASTE HANDLING	99.12				Particulate Matter (PM)	B	LOADING WASTE SILOS IS CONTROLLED VIA BOILER BAGHOUSE, WHEN UNLOADED ASH IS MIXED WITH WATER.	0		BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	ASH COVEYING #4	99.12		10	T/H	Particulate Matter (PM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	ASH SILO	99.12		12	T/H	Particulate Matter (PM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	#4 ASH SYSTEM - TRUCK LOADING	99.12		650	T/H	Particulate Matter (PM)	P	DUST SUPPRESSANT	95	%	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	ASH STORAGE AND HANDLING, S17 (07-A-962P)	99.12		250	TONS	Particulate Matter (PM)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	09/19/2008 ACT	FIBER ASH STORAGE BIN/ LOADOUT	99.12				Particulate Matter (PM)	A	DUST COLLECTOR	0.005	GR/DSCF	BACT-PSD
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	DIRECT REDUCED IRON MATERIAL HANDLING	99.12				Particulate Matter (PM)	B	BUILDING ENCLOSURE, ENCLOSURES, BAGHOUSE	0.47	LB/H	BACT-PSD
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	COAL AND IRON ORE UNLOADING & CONVEYING TO STORAGE (3)	99.12				Particulate Matter (PM)	B	USE OF ENCLOSURES AND A BAGHOUSE	0.93	LB/H	BACT-PSD
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	ALLOY, FLUX, CARBON, LIMESTONE, COKE HANDLING (2)	99.12				Particulate Matter (PM)	B	USE OF ENCLOSURES AND A BAGHOUSE	1.4	LB/H	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	04/26/2006 ACT	ASH HANDLING	99.12		105	T/H	Particulate Matter (PM)	A	FABRIC FILTERS	0.01	GR/DSCF	BACT-PSD
CO-0055	LAMAR LIGHT & POWER POWER PLANT	02/03/2006 ACT	ASH AND INERT (SAND) HANDLING/STORAGE/DISPOSAL	99.12		40	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	HIGH EFFICIENCY FABRIC FILTER BAGHOUSE	0.169	LB/T	BACT-PSD
CO-0057	COMANCHE STATION	07/05/2005 ACT	RECYCLE ASH HANDLING	99.12				Particulate matter, filterable < 10 µ (FPM10)	A	SILOS ARE EQUIPPED WITH BAGHOUSES, MIXERS ARE EQUIPPED WITH SCRUBBERS	0.01	GR/DSCF	BACT-PSD
CO-0057	COMANCHE STATION	07/05/2005 ACT	FLY ASH/ FGD WASTE HANDLING	99.12				Particulate matter, filterable < 10 µ (FPM10)	B	UNLOADING OF FLY ASH TO WASTE SILOS IS CONTROLLED BY THE BOILER BAGHOUSE, WHEN WASTE ASH SILOS ARE UNLOADED, FLY ASH IS MIXED WITH WATER.	0		BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	ASH COVEYING #4	99.12		10	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	ASH SILO	99.12		12	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0086	UNIVERSITY OF NORTHERN IOWA	05/03/2007 ACT	#4 ASH SYSTEM - TRUCK LOADING	99.12		650	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	DUST SUPPRESSANT	95	%	BACT-PSD
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	08/08/2007 ACT	ASH STORAGE AND HANDLING, S17 (07-A-962P)	99.12		250	TONS	Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.005	GR/DSCF	BACT-PSD
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	09/19/2008 ACT	FIBER ASH STORAGE BIN/ LOADOUT	99.12				Particulate matter, filterable < 10 µ (FPM10)	A	DUST COLLECTOR	0.005	GR/DSCF	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	ASH HANDLING	99.12		0		Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTER	0.005	GR/DSCF	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	34-08 ASH HYDRATION AREA	99.12		330	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	WET SUPPRESSION, COVERED CONVEYORS, ENCLOSED DROP POINTS, LOWERING TUBES FOR DIVERTING MATERIALS TO STORAGE PILES AND BEST OPERATING PRACTICES ARE BACT FOR MATERIAL HANDLING.	1.31	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	35-08 RAIL CAR BED ASH/FLY ASH LOADING	99.12		330	T/YR	Particulate matter, filterable < 10 µ (FPM10)	P	WET SUPPRESSION, COVERED CONVEYORS, ENCLOSED DROP POINTS, LOWERING TUBES FOR DIVERTING MATERIALS TO STORAGE PILES AND BEST OPERATING PRACTICES ARE BACT FOR MATERIAL HANDLING.	0.61	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	37-08A FLY ASH PUG MILLS	99.12		266	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	WET SUPPRESSION, COVERED CONVEYORS, ENCLOSED DROP POINTS, LOWERING TUBES FOR DIVERTING MATERIALS TO STORAGE PILES AND BEST OPERATING PRACTICES ARE BACT FOR MATERIAL HANDLING.	0.64	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	3708B BED ASH PUG MILLS	99.12		266	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	WET SUPPRESSION, COVERED CONVEYORS, ENCLOSED DROP POINTS, LOWERING TUBES FOR DIVERTING MATERIALS TO STORAGE PILES AND BEST OPERATING PRACTICES ARE BACT FOR MATERIAL HANDLING.	0.64	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	38-08 ASH LANDFILL OPERATIONS	99.12				Particulate matter, filterable < 10 µ (FPM10)	P	WET SUPPRESSION, COVERED CONVEYORS, ENCLOSED DROP POINTS, LOWERING TUBES FOR DIVERTING MATERIALS TO STORAGE PILES AND BEST OPERATING PRACTICES ARE BACT FOR MATERIAL HANDLING.	591.44	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	BED ASH SILO & FLY ASH SILO	99.12		4000	CFM EACH	Particulate matter, filterable < 10 µ (FPM10)	N		0.34	LB/H	BACT-PSD
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	ASH LOADING	99.12		100	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	TRUCK LOADING CHUTE SEALS TO TRUCK WITH NEGATIVE PRESSURE VENT BACK TO SILOS	0.07	LB/H	BACT-PSD
LA-0221	LITTLE GYPSY GENERATING PLANT	11/30/2007 ACT	BED ASH LOADING AND UNLOADING TO TRUCKS	99.12		250	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	CLOSED VENT SYSTEM THAT VENTS BACK TO THE ASH SILO	0		BACT-PSD
LA-0221	LITTLE GYPSY GENERATING PLANT	11/30/2007 ACT	BED ASH UNLOADING TO LANDFILL	99.12		250	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	BEST OPERATING PRACTICES	1.05	LB/H	BACT-PSD
LA-0221	LITTLE GYPSY GENERATING PLANT	11/30/2007 ACT	FLY ASH LOADING TO TRUCKS	99.12		250	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	CLOSED VENT SYSTEM THAT VENTS BACK TO THE ASH SILO	0		BACT-PSD
LA-0221	LITTLE GYPSY GENERATING PLANT	11/30/2007 ACT	FLY ASH UNLOADING TO LANDFILL	99.12		1000	T/H	Particulate matter, filterable < 10 µ (FPM10)	P	BEST OPERATING PRACTICES	2.11	LB/H	BACT-PSD

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNITS	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
LA-0221	LITTLE GYPSY GENERATING PLANT	11/30/2007 ACT	FLY ASH PILE	99.12		3310000	T/YR	Particulate matter, filterable < 10 µ (FPM10)	P	DUST SUPPRESSION	25.11	LB/H	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	ASH SILO	99.12		37.5	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	FABRIC FILTERS	0.001	LB/H*	BACT-PSD
LA-0223	BIG CAJUN I POWER PLANT	01/08/2008 ACT	ASH TRUCK LOADING	99.12		240	T/H	Particulate matter, filterable < 10 µ (FPM10)	A	CLOSED VENT SYSTEM THAT VENTS BACK INTO THE ASH SILO	0.18	LB/H	BACT-PSD
NV-0036	TS POWER PLANT	05/05/2005 ACT	ASH, LIME & CARBON SILOS	99.12				Particulate matter, filterable < 10 µ (FPM10)	A	BIN VENTS	0.02	GR/DSCF	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	04/09/2010 ACT	ASH HANDLING	99.12		0		Particulate matter, filterable < 2.5 µ (FPM2.5)	A	FABRIC FILTER	0.005	G/DSCF	BACT-PSD
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	SCRAP, COAL, IRON ORE BARGE UNLOADING	99.12		8250647	T/YR	Particulate matter, fugitive	N		6.15	T/YR	BACT-PSD
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	COAL AND IRON ORE UNLOADING & CONVEYING TO STORAGE (3)	99.12				Particulate matter, fugitive	N		2.4	T/YR	BACT-PSD
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	ALLOY, FLUX, CARBON, LIMESTONE, COKE HANDLING (2)	99.12				Particulate matter, fugitive	N		5.79	T/YR	BACT-PSD
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	FLYASH HANDLING SYSTEM (6)	99.12		95.4	T/H	Particulate matter, fugitive	B	BAGHOUSE AND TOTALY ENCLOSED STORAGE BINS, SILOS, AND TRUCK LOADING. NO OPEN DROP HEIGHT.	0.03	LB/H	BACT-PSD
FL-0318	HIGHLANDS ETHANOL FACILITY	12/10/2009 EST	Roadway Emissions and Biomass Handling	99.12		0		Particulate matter, total (TPM)	B		0.005	GR/DSCF	BACT-PSD
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	12/23/2010 ACT	Ash Handling System and Building	99.12		0		Particulate matter, total (TPM)	B	Fabric Filter	5	% OPACITY	BACT-PSD
IA-0099	POWER PLANT	08/17/2011 ACT	Ash handling	99.12		12	T/H	Particulate matter, total (TPM)	A	Baghouse	0.005	GR/DSCF	BACT-PSD
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	SCRAP, COAL, IRON ORE BARGE UNLOADING	99.12		8250647	T/YR	Particulate matter, total (TPM)	B	USE OF ENCLOSURES, MINIMIZING DROP HEIGHT, AND VENTING TRANSFER POINTS TO A BAGHOUSE	0.93	LB/H	BACT-PSD
IA-0099	POWER PLANT	08/17/2011 ACT	Ash handling	99.12		12	T/H	Particulate matter, total < 10 µ (TPM10)	A	baghouse	0.005	GR/DSCF	BACT-PSD
LA-0231	LAKE CHARLES GASIFICATION FACILITY	06/22/2009 ACT	SAND/BOTTOM ASH SILOS AND DAY BINS	99.12		2699	SCFM	Particulate matter, total < 10 µ (TPM10)	A	FABRIC FILTERS	0.12	LB/H	BACT-PSD
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	DIRECT REDUCED IRON MATERIAL HANDLING	99.12				Particulate matter, filterable < 2.5 µ (FPM2.5)	B	BUILDING ENCLOSURE, ENCLOSURES, BAGHOUSE	0.47	LB/H	LAER
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	SCRAP, COAL, IRON ORE BARGE UNLOADING	99.12		8250647	T/YR	Particulate matter, filterable < 2.5 µ (FPM2.5)	B	USE OF ENCLOSURES, MINIMIZING DROP HEIGHT, AND VENTING TRANSFER POINTS TO A BAGHOUSE	0.93	LB/H	LAER
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	COAL AND IRON ORE UNLOADING & CONVEYING TO STORAGE (3)	99.12				Particulate matter, filterable < 2.5 µ (FPM2.5)	B	USE OF ENCLOSURES AND A BAGHOUSE	0.93	LB/H	LAER
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	ALLOY, FLUX, CARBON, LIMESTONE, COKE HANDLING (2)	99.12				Particulate matter, filterable < 2.5 µ (FPM2.5)	B	USE OF ENCLOSURES AND A BAGHOUSE	1.4	LB/H	LAER
OH-0315	NEW STEEL INTERNATIONAL, INC., HAVERHILL	05/06/2008 ACT	DIRECT REDUCED IRON MATERIAL HANDLING	99.12				Particulate matter, fugitive	N		1.43	T/YR	LAER
SC-0149	KLAUSNER HOLDING USA, INC	01/03/2013 ACT	FLY ASH STORAGE SILO EU012	99.12		0		Particulate matter, filterable (FPM)	A	BAGHOUSE	0.005	GR/DSCF	OTHER CASE-BY-CASE
SC-0149	KLAUSNER HOLDING USA, INC	01/03/2013 ACT	FLY ASH STORAGE SILO EU012	99.12		0		Particulate matter, filterable < 10 µ (FPM10)	A	BAGHOUSE	0.005	GR/DSCF	OTHER CASE-BY-CASE
SC-0149	KLAUSNER HOLDING USA, INC	01/03/2013 ACT	FLY ASH STORAGE SILO EU012	99.12		0		Particulate matter, filterable < 2.5 µ (FPM2.5)	A	BAGHOUSE	0.005	GR/DSCF	OTHER CASE-BY-CASE
CO-0057	COMANCHE STATION	07/05/2005 ACT	RECYCLE ASH HANDLING	99.12				Particulate Matter (PM)	A	RECYCLE ASH MIXERS ARE EQUIPPED WITH SCRUBBERS, RECYCLE ASH SILOS ARE EQUIPPED WITH BAGHOUSES	0.01	GR/DSCF	

Note: Data is based on a RBLC review from January 1, 2005 through August 24, 2015.

Appendix B: BACT Analysis Support Documents

BACT Analysis Support for EU ID 113, Large CFB Coal and Biomass-fired Boiler

Rubino, Joe

From:	Novogoratz, David M <dmnovogoratz@babcock.com>
Sent:	Monday, February 01, 2016 6:03 AM
To:	Solan, John
Cc:	Rubino, Joe; Julie Ackerlund; Courtney Kimball (ckimball@slrconsulting.com); Gittinger, Jim S
Subject:	RE: UAF CFB BACT Analysis for NOx/SOx/PM2.5

John – please accept my apologies for the long delay in responding. Please find our response below:

The following response is based on the assumption that the boiler is fully operational and any of the below emissions control equipment will be retrofit to the existing plant.

1) What is the control efficiency of the current baghouse design (based on guaranteed PM emissions rates)? Is there a different type of bag available that might perform better (without significantly impacting the performance of the boiler)?

   Response – baghouses are barrier filters and are not designed to a "control efficiency" as would be with other types of PM control equipment, such as an electrostatic precipitator. The filter media itself is a barrier to solid particles passing through the filter; in other words particle penetration through the filter media is constant regardless of the mass loading.

   The filter media was selected based on a number of factors including emission, longevity, pressure loss and suitability for gas composition and operating temperature range. We are not aware of a different filer media that would provide a reduction in PM emissions.

2) Would post combustion control of sulfur (in addition to limestone injection into the combustor) be possible? If so, what kind of reduction might be possible (in % capture of remaining flue gas sulfur content). What would be required (in terms of required space and boiler modifications) to include post combustion sulfur control?

   Response - Yes, there are technologies that could be considered for additional post combustion SO_2 control. In order of capital cost expenditure, the SO_2 emission of 0.19 lb/MBtu SO_2 could be reduced further by 1) Dry Sorbent Injection (DSI, sodium bicarbonate or specialized hydrated lime) or 2) semi-dry scrubbing.

   DSI
   A DSI system would require a silo for reagent storage, pneumatic conveying and reagent distribution upstream of the PJFF. Potentially the baghouse ash handling system capacity would also need to be increased depending on the sorbent injection rate.

   Potentially we could achieve 0.05 lb SO_2/MBtu with SBC. However the sodium will react with NO_x to create a visible brown plume. Additional NO_x reduction may be required to minimize or prevent the brown plume. It should also be considered that any excess ammonia slip will show up as condensable particulate. The space required, enough for a 14 ft diameter silo, roadway access to the silo and a 40'x40' mill building. No boiler modifications would be necessary.

   Semi-Dry Scrubbing
   A Spray Dry Absorber (SDA) technology would be located at grade between the air heater and the baghouse. The current baghouse and filter media is capable of handling the higher solids loading from the SDA. The system

would utilize a baghouse flyash recycle system which will activate a portion of the un-reacted CaO in the flyash. The recycle slurry, when sprayed through the atomizer, will reduce the SO_2 emission, possibly without the need for any additional reagent depending on the level of SO_2 reduction required. With SDA technology we would anticipate an SO_2 emission of 0.04 lb SO_2/MBtu.

The SDA vessel would be approximately 30 ft in diameter. Two 14 ft diameter silos (1 lime, 1 recycle), slurry pump enclosure (20x30'), with new flue work connecting the AH outlet flue to the SDA, and the SDA outlet flue to the PJFF inlet would be required. The SDA will add about 4 in WG plus the flue work (say 2 in WG) to the pressure drop. The ID fan capacity would most likely change due to the increased pressure loss. Additionally, the fly ash conveying under the baghouse will have to be checked for capacity.

3) Is it possible to add an SCR to this design? What would be required to do so? What % reduction in NOx emissions could reasonably be expected?

   Response: To operate at optimal temperatures the SCR would be installed in the flow path downstream of the Multiclone dust collector and upstream of the economizer. As there is minimal space available we feel this would be a very complicated arrangement and would require a detailed analysis to determine if it would be practical. With an SCR the NOx reduction would be approximately 80%.

4) Is it possible to add an SNCR? What would be required to do so? What % reduction in NOx emissions could reasonably be expected?

   Response: We would expect minimal NOx reduction with an SNCR, in the range of 10-20%

For each viable technology identified in your answers to the questions above, please provide the following information:

1) Cost estimate for the equipment necessary to install and operate the emissions control device. Construction cost estimates will be completed by SCI if necessary.

   Response :
   DSI budgetary material cost - $1,500,000
   SDA budgetary material cost - $8,000,000
   SNCR budgetary material cost - $1,000,000
   SCR budgetary material cost - $6,000,000
2) An estimate of operating and maintenance costs (excluding the purchase of reagents) for each emissions control device, if applicable.
   Response:
   DSI = 200 kW
   SDA = 260 kW not including ID fan power
   SNCR = Minimal
   SCR = 70 kW not including ID fan power (assuming electric vaporization of the ammonia)

3) Reagent consumption rates at MCR (and 40% of MCR, if possible), where applicable. For the moment, you can assume the reagent will be 29% Aq. Ammonia. This may change to urea if UAF is not able to store sufficient volumes of aq. Ammonia on site due to safety concerns.

   Response:
   DSI utilizing SBC = 300 lb/hr @ MCR
   SDA utilizing $Ca(OH)_2$ = 0-70 lb/hr @ MCR depending on SO_2 emission required
   SNCR = 20 lb/hr @ MCR
   SCR = 60 lb/hr @ MCR

Regards,

David Novogoratz
Manager, Environmental Product Lines
The Babcock & Wilcox Company
Office: (281) 405-6813 • Mobile: (713) 882-8601 • Fax: (281) 405-6893
dmnovogoratz@babcock.com
www.babcock.com

From: Solan, John [mailto:SolanJohn@stanleygroup.com]
Sent: Friday, January 15, 2016 10:09 AM
To: Novogoratz, David M
Cc: Rubino, Joe; Julie Ackerlund; Courtney Kimball (ckimball@slrconsulting.com); Gittinger, Jim S
Subject: EXTERNAL:RE: UAF CFB BACT Analysis for NOx/SOx/PM2.5

Dave,
Can you please give me an update on the status of this request?
Thanks
-John

From: Solan, John
Sent: Friday, October 30, 2015 10:50 AM
To: Novogoratz, David M <dmnovogoratz@babcock.com>
Cc: Rubino, Joe <RubinoJoe@stanleygroup.com>; 'Julie Ackerlund' <j.ackerlund@bresnan.net>; Courtney Kimball (ckimball@slrconsulting.com) <ckimball@slrconsulting.com>
Subject: UAF CFB BACT Analysis for NOx/SOx/PM2.5

Dave,

Could you please answer the following questions relating to the UAF CFB that Barberton is currently designing?

Note: Please craft your response with the assumption that the boiler is fully operational prior to starting the installation of any emissions control equipment that you identify in your answers. Feel free to contact me if you need information relating to available space on site.

1) What is the control efficiency of the current baghouse design (based on guaranteed PM emissions rates)? Is there a different type of bag available that might perform better (without significantly impacting the performance of the boiler)?
2) Would post combustion control of sulfur (in addition to limestone injection into the combustor) be possible? If so, what kind of reduction might be possible (in % capture of remaining flue gas sulfur content). What would be required (in terms of required space and boiler modifications) to include post combustion sulfur control?
3) Is it possible to add an SCR to this design? What would be required to do so? What % reduction in NOx emissions could reasonably expected?
4) Is it possible to add an SNCR? What would be required to do so? What % reduction in NOx emissions could reasonably expected?

For each viable technology identified in your answers to the questions above, could you please provide the following information:

1) Cost estimate for the equipment necessary to install and operate the emissions control device. Construction cost estimates will be completed by SCI if necessary.
2) An estimate of operating and maintenance costs (excluding the purchase of reagents) for each emissions control device, if applicable.
3) Reagent consumption rates at MCR (and 40% of MCR, if possible), where applicable. For the moment, you can assume the reagent will be 29% Aq. Ammonia. This may change to urea if UAF is not able to store sufficient volumes of aq. Ammonia on site due to safety concerns.

Thanks in advance for your help. Please call me if you have questions about any of the information requested.
-John

Stanley Consultants 100 Years

John Solan, P.E. | **Senior Mechanical Engineer**
8000 S. Chester Street, Suite 500 | Centennial, CO 80112
303.649.7830 (phone) | [303.799.7830] (fax)
www.stanleyconsultants.com

From: Rubino, Joe [RubinoJoe@stanleygroup.com]
Sent: July 08, 2016 1:49 PM
To: Courtney Kimball
Cc: Julie Ackerlund; Solan, John
Subject: UAF BACT Report

Hi Courtney –

Sorry I missed your call. We have run into an issue with obtaining further information from B&W on the DSI system. John confirmed the last piece of info I was waiting on this morning. According to our contact at B&W, they specified the DSI system for the new boiler to primarily reduce acid gases (HCl and HF) only. They would expect the control to have some impact on SO_2 emissions; however they have not been asked to provide a guarantee and would likely change the design if the intent was to significantly reduce SO_2 emissions. Therefore the original capital costs we obtained would apply for a system designed to reduce SO_2 emissions by approximately 75%.

B&W has not given us details on additional costs, but their communication implies that they would want to be paid to evaluate the SO_2 reductions that could be expected with the current system, before any upgrades. Additionally, they would want money to consider how the existing system would need to be upgraded to achieve BACT level control for SO_2. These additional dollars would impact design project costs.

Let me know if you feel comfortable moving ahead with the cost information submitted previously or if you would want to have a call with John and Julie to discuss further. Thanks.

Joe

Stanley Consultants 100 Years

Joe Rubino | Environmental Services Department Manager
8000 South Chester Street Suite 500 | Centennial, Colorado 80112
303.925.8282 (phone) | 515.450.3563 (mobile) | 303.799.8107 (fax)
rubinojoe@stanleygroup.com
www.stanleyconsultants.com

"Creativity can solve almost any problem. The creative act, the defeat of habit by originality, overcomes everything."

NO_X BACT Analysis Support for EU IDs 3 and 4, Mid-sized Diesel-fired Boiler

Dale Pfaff
Regional Sales Manager

January 19, 2016

Mr. John Solan
Stanley Consultants
8000 S. Chester Street
Suite 500
Centennial, CO 80112
P: (303) 649-7830

SUBJECT: STANLEY CONSULTANTS - REQUEST FOR QUOTATION UNIVERSITY OF ALASKA FAIRBANKS ULTRA™ SCR SYSTEM FOR UNIT 3 PACKAGE BOILER FTEK PROPOSAL NO. 16-B-008

Dear Mr. Solan:

Fuel Tech Inc. (FTEK) is pleased to provide our budget Proposal 16-B-008 to Stanley Consultants for the University of Alaska Fairbanks (UAF) emissions study. Our offering includes the preliminary and budgetary information for a ULTRA™ SCR system to be applied on the UAF Unit 3 Package Boiler located in Fairbanks, AK.

System and Unit Summary:

UAF Unit 3 is a 180 MMBTU/hr package boiler that fires an ultra-low sulfur No. 2 fuel oil with a NOx baseline of 0.175 lb/MMBTU. FTEK has evaluated the data and is recommending an SCR for the package boiler that will utilize FTEK's ULTRA urea conversion system for the SCR reagent feed.

FTEK Process Design Information:

The following information was used to determine the process design conditions for FTEK's systems:

Emissions and SCR Performance Requirements		
Description	**U/M**	**Qty**
Package Boiler Heat Input	MMBTU/hr	180
Flue Gas Flow Exiting HRSG	(lb/hr)	126,000
Boiler NOx Emission Rate (Baseline)	lb/MMBTU	0.175
SCR Outlet NOx Emission Rate	lb/MMBTU	0.026
Expected NOx Reduction	%	85
Ammonia Slip @ Stack, Dry at Ref. O2.	ppmd	≤ 5
Expected Catalyst Lifetime	hours	16,000
Catalyst Draft Loss (dirty)	in H2O	≤ 2.0

Fuel Tech Inc *• 27601 Bella Vista Parkway • Warrenville, IL 60555*
Phone: (970) 368-6019 • Cell: (847) 504-6650
dpfaff@ftek.com • www.ftek.com

Catalyst and NH3 System Design		
Description	**U/M**	**Qty**
Catalyst Type (Honeycomb or Plate)		Honeycomb
Pitch	mm	4.23
# of Layers per Reactor	#	1
# of Reactors	#	1
Single Layer Depth	mm	850
Ammonia Consumption at Catalyst	lb/hr	10.5
SCR Minimum Operating Temperature	°F	375

ULTRA Process and System Requirements		
Description	**U/M**	**Qty**
Ambient Air temperature	°F	60
Mixed Air/NH3 Temperature at Reaction Chamber Outlet	°F	550
Ammonia Flow	lb/hr	10.3
Ammonia to air ratio	vol%	1.32
Total flow at reaction chamber outlet	scfm	296
Total flow at reaction chamber outlet	lb/hr	1303
NOxOUT flow	gph	5.4
Injection air	scfm	15
Decomposition Chamber Heat Input (Electrical Heater)	kW	68

FTEK Equipment and Engineering Scope of Supply:

The following is a summary of FTEK's scope of supply for the Unit 3 NOx reduction and reagent system:

- One (1) SCR reactor
    - The steel accounted for is the reactor box, internal supports, mixer, monorail, and external support members to tie-in to customer's load points. Structural steel to grade is not included.
- One (1) Ammonia Injection Grid (AIG) & associated balancing valves
- One (1) Lot, Catalyst
- One (1) Lot Ductwork Steel to/from SCR Reactor
    - FTEK assumes nine (9) tons of steel to supply ~ 60' of ductwork (assuming 4'x4' cross section).
- One (1) 6,000 gallon FRP Storage Tank
- One (1) Urea Forwarding Pump Module
- One (1) Metering/Distribution module which includes the following:

- Two (2) 100% Capacity Blowers
- Two (2) 100% Capacity Electric heaters
- One (1) PLC control panel with A/C & heater
- One (1) Heater/Drive control panel with A/C & heater

- One (1) Decomposition Chamber with injection.
- Twenty (20) field man days of onsite time split between two separate trips.
- All equipment and system engineering with drawings, O&MMs, and Training Manuals.

Typical Scope of Supply by Others:

1. Offloading of All Fuel Tech Supplied Equipment
2. Demolition of existing structures and ductwork as needed
3. Installation Labor and Materials for Fuel Tech, Inc. Supplied Equipment.
4. Structural Steel and Foundations
5. Platforms, Stairs, Ladders, etc Required to Access Equipment or Devices
6. Buildings for Freeze Protection and Climate Control
7. Interconnecting Piping and Wiring of Fuel Tech, Inc. Supplied Equipment
8. Installation Engineering, BOP Engineering, and Installation Project Management
9. Insulation Materials and Labor for Decomposition Chamber. Insulation and Temperature Indication Materials and Labor for AIG Piping and AIG Manifold. Must Maintain 500 °F @ Furthest (coolest) Point in AIG Piping.
10. MCCs and Starters for All FTI-provided Equipment, wired directly to Motors
11. Sootblowers for Catalyst as needed
12. Demineralized water for intermittent flush.
13. Air Compressors.
14. Chemical Supply: Licensed Quality or Industrial Grade urea
15. Permits as Required
16. Taxes as Required
17. System Performance Testing
18. Estimated System Utilities
19. Shipping is Ex Works
20. NOx analyzer is not included.

Typical Project Schedule

The expected project schedule from receipt of purchase order to the delivery of equipment to the site is approximately forty-five (45) weeks. Actual duration of project will be determined after receipt of official bid specifications.

Pricing

The budgetary and preliminary pricing for the FTEK equipment and services quoted above is (± 20%):

Work Scope	Price
Estimated Capital Cost of FTEK Supplied Equipment and Services	$ 850,000

An installation estimate (including items detailed in the Scope of Supply by Others) for study purposes would be approximately 2.0 times the capital cost. Therefore the installation estimate would be ~$1,700,000 (±30%). Obviously, this cost estimate is site unseen and would require design drawings followed by a site walk down by an approved, experienced installation contractor familiar with Alaska labor and UAF work rules.

This FTEK offering is based on our standard equipment specifications and suppliers. Commercial terms are based on Appendix C-1, Field Service Rates and FTEK's Standard Terms and Conditions, Appendix C-3.

We trust this information meets your needs. Upon completion of your review, please do not hesitate to contact me if there are any questions or comments. Thank you.

Sincerely,

Dale Pfaff

Dale Pfaff
Mountain Regional Sales Manager

cc: Joe Rubino, Stanley
William Cummings, FTEK
Kevin Dougherty, FTEK
Joe DiFiglio, FTEK
Stewart Bible, FTEK
Caleb Triece Thomas, FTEK
Doug Kirk, FTEK
Dave Diggins, Diggins Inc.

EXHIBIT C1 – FTEK FIELD SERVICE RATES

RATES

Billing will be based on rates in effect at time service is rendered. Rates apply within the USA, but excluding the States of Alaska and Hawaii. The per diem rates listed below are for an 8-hour man-day, during normal working hours. Travel time is working time. Parts and expenses are additional.

	Daily Rate	Hourly Rate
Technician	$1,425.00	$ 180.00
Project Engineer	$1,575.00	$ 195.00
Process/Test Engineer	$1,675.00	$ 210.00
Project Manager	$1,675.00	$ 210.00
Engineering Manager/Director	$2,075.00	$ 260.00
VP Technology	$2,275.00	$ 285.00

The rates quoted are valid through January 31, 2017. The per diem rate for specialist service and services performed outside the Continental United States will be quoted upon request.

NORMAL WORKING HOURS AND DAYS

8:00 A.M. to 5:00 P.M., including sufficient time for lunch, Monday through Friday, except legal holidays, at location of customer's plant.

OVERTIME

Overtime will be billed at 1.5 times the prevailing hourly rate. Overtime is defined as all hours worked under twelve (12) on the employee's first scheduled off day (Saturday), and all hours worked under twelve (12) and over eight (8) hours for a day on the job (Standard hourly rate X 1.5).

DOUBLE TIME

Double time will be billed at two (2) times the prevailing hourly rate. Double time is defined as all hours worked over twelve (12) on any day, all hours worked on the employee's second scheduled off day (Sunday) and all hours on observed holidays.

EXPENSES

1. **TRAVEL**
   - a) Automobile travel at the rate of $0.54 per mile.
   - b) Travel expenditures will be charged per round-trip from the Fuel Tech personnel's point of origin, plus local travel.
   - c) Expenses for travel will be at cost, which will be by airplane, rail or auto, whichever is the most expeditious under given circumstances. Air travel will be at prevailing available rates; Tourist Class within the Continental United States and Business Class for International flights.
2. **LIVING**
   - a) Actual expenses for lodging, meals and incidental costs.
   - b) Telephone calls and wires as required in connection with details of the job will be charged at cost.

GENERAL CONDITIONS

- Fuel Tech representatives are authorized to act in a consulting capacity only. Operation and control of all equipment shall rest with others. Fuel Tech shall not be held responsible for any damage through any misoperation or misunderstanding.

- Customer shall render all reasonable assistance to Fuel Tech representative. Necessary working and storage space, including field office, if required, shall be furnished by the customer. Customer shall be responsible for insuring the Fuel Tech representative has full access to the equipment to be serviced and the scheduling of the required boiler loading.

- It will be the responsibility of the customer to furnish qualified tradesmen when required, to work with our representative.

- In the event of any labor disputes, it shall be left to the judgment of the Fuel Tech representative on the jobsite as to their course of action. Fuel Tech's representative will in no way become involved in labor disputes.

SPARE PARTS

Spare parts are available through our Warrenville, IL office. An inventory of critical parts is kept on-site for injectors. Fuel Tech works with key local suppliers to provide quick turnaround for spare parts orders time. Parts and expenses are additional.

RENTAL EQUIPMENT

Customer shall, at its own cost and expense, keep the Equipment in good repair, condition, and working order and shall furnish any and all parts, mechanisms, and devices required to keep the Equipment in good working order. Customer hereby assumes and shall bear the entire risk of loss or damage to the Equipment from any and every cause whatsoever. In the event of loss or damage of any kind whatever to the Equipment, Customer shall, at Fuel Tech's option:

1. place the Equipment in good repair, condition, and working order; or,
2. replace the Equipment with identical Equipment in good repair, condition and working order; or,
3. pay Fuel Tech the replacement cost of the Equipment.

EXHIBIT C3 - FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

These terms and conditions shall be part of the attached proposal and shall become part of the contract entered into between FUEL TECH, INC. (Fuel Tech), and the Buyer. Deviations from these terms and conditions must be agreed to in a writing signed by Fuel Tech and the Buyer. Fuel Tech hereby gives notice of its objection to any different or additional terms or conditions unless such different or additional terms or conditions are agreed to in a writing signed by Fuel Tech and Buyer.

1. TERMS OF PAYMENT:

All invoices are payable net thirty (30) days from date of invoice. Buyer shall pay interest at the rate of ten percent (10%) per annum on all overdue amounts. Buyer shall pay all sales tax, use tax, excise tax, or other similar taxes.

2. DELAYS:

If shipments are delayed by Buyer, payment shall be due on and warranty coverage shall begin to run from thirty days after the original shipment date specified in the contract or thirty (30) days after notification to Buyer that equipment is ready to ship, whichever is earlier. Risk of loss shall pass to Buyer at the time that equipment is identified, and any costs caused by such delay shall be borne by Buyer.

If shipments are delayed by Buyer, Fuel Tech will ship the equipment no later than sixty (60) days after initial notification to the Buyer that the equipment is ready for shipment. Buyer agrees either (1) to provide Fuel Tech an appropriate “ship to” address and to accept delivery or (2) pay reasonable storage charges for the equipment beginning sixty (60) days after initial notification to Buyer that equipment is ready to ship.

3. PERFORMANCE GUARANTEE:

Buyer warrants that the operating conditions of the Unit are those specified in the Process Design Table. Buyer is solely responsible for the accuracy of that operating condition information, and all performance guarantees and equipment warranties granted by Fuel Tech shall be void if that operating condition information is inaccurate or is not met. All performance guarantees and equipment warranties are conditioned on Buyer timely providing all of the equipment, materials, chemicals, utilities, and services that it has agreed to provide, on operating the Unit within the operating conditions specified in the Process Design Table, and on using reagent of license grade quality in the operation of the Unit.

4. EQUIPMENT WARRANTY:

Fuel Tech warrants that the equipment it provides shall be free from defects in design, workmanship, and material at the time the equipment is delivered and for a period of twelve (12) months after initial operation, or eighteen (18) months from shipment of equipment, whichever occurs first. Fuel Tech does not warrant wear parts such as injection tips, cooling shields, pump diaphragms, check valves, solenoids, pump impellers, pump wear rings, pump seals, valve packing, and valve seats.

All warranties made by the manufacturer of the equipment (if that manufacturer is any entity other than Fuel Tech) shall be assigned by Fuel Tech to the Buyer, if such assignment is permissible by law and contract. Warranty coverage starts at shipment of equipment or thirty (30) days after notification to Buyer that equipment is ready to ship.

5. DISCLAIMER OF WARRANTIES:

Fuel Tech warrants its equipment and the performance of its equipment solely in accordance with the equipment warranty and performance guarantee contained in this proposal and makes no other representations or warranties of any other kind, express or implied, by fact or by law. All warranties other than those specifically set forth in this proposal are expressly disclaimed. Notwithstanding anything to the contrary contained in this proposal, Fuel Tech shall have no obligation hereunder with respect to any equipment which (i) has been improperly repaired or altered; (ii) has been subjected to misuse, negligence or accident; (iii) has been used in a manner contrary to Fuel Tech’s written instructions; (iv) is comprised of materials provided by or a design specified by the Buyer; or (v) has failed as a result of ordinary wear and tear. **FUEL TECH SPECIFICALLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, AND DISLCAIMS THE IMPLIED WARRANTY OF MERCHANTABILITY, THE IMPLIED WARRANTY OF**

FITNESS FOR A PARTICULAR PURPOSE, AND ANY OTHER IMPLIED WARRANTIES OF DESIGN, CAPACITY, OR PERFORMANCE RELATING TO THE EQUIPMENT.

6. LIMITATION OF LIABILITY:

Buyer's sole remedy under Section 5 (equipment warranty) and Section 4 (performance guarantee) shall be to allow Fuel Tech, at Fuel Tech's option, either to repair, replace, or supplement the equipment to meet the performance guarantee, or, in the event that those options are either not feasible or such repairs, replacement or supplementation continue to fail to meet the warranties as determined by Fuel Tech on a commercially reasonable basis, then Fuel Tech will repay to the Buyer the purchase price of the defective work. NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED IN THIS PROPOSAL, FUEL TECH'S TOTAL LIMIT OF LIABILITY ON ANY CLAIM, WHETHER FOR BREACH OF CONTRACT, BREACH OF WARRANTY, TORT, NEGLIGENCE, STRICT LIABILITY, OR ANY OTHER LEGAL THEORY, FOR ANY LOSS OR DAMAGE ARISING OUT OF, OR CONNECTED TO, OR RESULTING FROM THIS AGREEMENT, INCLUDING WITHOUT LIMITATION AMOUNTS INCURRED BY FUEL TECH OR BUYER IN ATTEMPTING TO REPAIR, REPLACE, OR SUPPLEMENT THE EQUIPMENT OR MEET A PERFORMANCE GUARANTEE PROVIDED BY FUEL TECH TO BUYER, IF ANY, SHALL BE LIMITED TO THE CONTRACT PRICE TO BE PAID BY BUYER PURSUANT TO THE CONTRACT.

7. EXCLUSION OF CONSEQUENTIAL DAMAGES:

NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED IN THIS PROPOSAL, IN NO EVENT SHALL FUEL TECH BE LIABLE FOR ANY INDIRECT, CONSEQUENTIAL, INCIDENTAL, SPECIAL, OR PUNITIVE DAMAGES, INCLUDING BUT NOT LIMITED TO LOSS OF CAPITAL, LOSS OF REVENUES, LOSS OF PROFITS, LOSS OF ANTICIPATORY PROFITS, LOSS OF BUSINESS OPPORTUNITY, DAMAGE TO EQUIPMENT OR FACILITIES, COST OF SUBSTITUTE NOx REDUCTION SYSTEMS, DOWNTIME COSTS, GOVERNMENT FINES, OR CLAIMS OF CUSTOMERS, EVEN IF ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

8. RESPONSIBILITY FOR THIRD PARTIES

Buyer shall at all times be responsible for the acts and omissions of its subcontractors and of any other third parties hired or retained or contracted by Buyer to perform work or provide equipment related to the system provided by Fuel Tech, including but not limited to third party design, systems integration, equipment tie-in, or process design changes. Fuel Tech shall have no responsibility for ensuring the accuracy of any such work or the performance of any equipment provided by subcontractors or third parties hired or retained or contracted by Buyer, and Buyer assumes all liability for any such work or equipment and for any failures in Fuel Tech's equipment caused by any such subcontractors or third parties hired or retained or contracted by Buyer. Buyer agrees to indemnify, hold harmless, and defend Fuel Tech from any claims, losses, damages, injuries, or failures caused by any such subcontractors or third parties.

9. CONFIDENTIALITY:

(a) "Confidential Information" means the confidential or proprietary designs, processes, trade secrets, and other information owned or controlled by Fuel Tech, embodied in or relating to Fuel Tech's design, construction and implementation of processes and systems for the reduction of NOx emissions from the specific combustion unit(s) for which Fuel Tech has been engaged to provide a technology solution (the "Site") by urea-based or ammonia-based NOx reduction processes including (i) non-catalytic, catalytic and combined catalytic and non-catalytic processes, (ii) urea treatment and handling processes and (ii) combustion or combustion modification. For avoidance of doubt, it is understood that Confidential Information may include, but is not limited to, such designs, processes, trade secrets and other information incorporated into Fuel Tech product offerings known as NOxOUT SNCR and ULTRA. The Know-How includes, but is not limited to: computational fluid dynamics modeling for the Site; design, construction and installation of chemical injection apparatus, control systems for monitoring and controlling chemical introduction and chemical composition of combustion effluents, chemical storage and delivery apparatus, and chemical mixing apparatus; business information relating to industry standards and regulatory matters and to sources of supply of chemicals and component equipment for reduction of NOx with effectiveness; and other aspects of chemical, metering, delivery, and control for efficient operation of the Site employing urea-based selective non-catalytic reduction or urea-based combined selective non-catalytic and catalytic reduction processes alone or in combination with combustion modification.

(b) Buyer agrees that it shall hold Confidential Information received from Fuel Tech in the strictest confidence, shall not use the Confidential Information for its own benefit except as necessary to fulfill the terms of the agreement between the parties, shall disclose the Confidential Information only to employees, agents, or representatives who have a need to know the Confidential Information, shall not disclose the Confidential Information to any third party, shall not copy the Confidential Information, shall not disassemble, decompile, or otherwise reverse engineer the Confidential Information and any inventions, processes, or products disclosed by Fuel Tech, and, in preventing disclosure of Confidential Information to third parties, shall use the same degree of care as for its own information of similar importance, but no less than reasonable care.

10. LICENSE AGREEMENT AND OTHER TERMS:

For a period not exceeding the life of the Site, Contractor, as licensor, grants to Buyer, as licensee, a nonexclusive license of the Technology (as defined below) to use it for Buyer's internal use at the Site. Buyer shall have no right to make, sell, transfer, license, or sublicense the Technology except that Buyer may transfer the license to a purchaser of the Site. Buyer may use the Technology at the Site in conjunction with Buyer' normal operation, maintenance or repair of the Site. The Technology shall not be considered as Buyer's property under "work for hire" or any other legal theory or principle, nor shall Buyer claim to own or have the right to use any future improvement of the Technology. In addition to its other remedies at law or in equity, either party may terminate this license at any time upon written notice if the other party is in material breach of the confidentiality or license terms set forth in Sections 9 and 10 hereof and fails to cure such breach within thirty (30) days following written notice of such breach. For purposes of this Section 10, "Technology" means the Confidential Information described in Section 9 above and, if applicable, U.S. Patent No. 7,090,810.

11. INDEMNIFICATION:

Each party to the Agreement ("Party" or collectively "Parties") shall defend, indemnify, and hold harmless the other Party and its employees, agents, and representatives from any third party claims, liabilities, lawsuits, costs, losses, or damages (collectively "Losses") that arise out of or result from any negligent or willful acts or omissions of the indemnifying Party's employees, agents, or representatives to the extent such Losses relate to personal injury or death or property damage ("Third Party Claims"). Where such Third Party Claims are the result of the joint or concurrent negligence or willful misconduct of the Parties or their respective agents, employees, representatives, subcontractors, or any third party, each Party's duty of indemnification shall be in the same proportion that the negligence or willful misconduct of such Party, its agents, employees, representatives, or subcontractors contributed to the Third Party Claims. The Party entitled to indemnity under this Agreement shall promptly notify the indemnifying Party of any indemnifiable Third Party Claims. The Party responsible for indemnification under this Agreement shall conduct and control the defense of the Third Party Claims. The Parties shall use their best efforts to cooperate in all aspects of the defense of any Third Party Claims. The indemnifying Party shall not be bound by any compromise or settlement made without its prior written consent.

12. FORCE MAJEURE

The Parties shall be excused from liability for delays in manufacture, delivery, or performance due to any events beyond the reasonable control of the Parties, including but not limited to acts of God, war, national defense requirements, riot, sabotage, governmental law, ordinance, rule, or regulation (whether valid or invalid), orders of injunction, explosion, strikes, concerted acts of workers, fire, flood, storm, failure of or accidents involving either Party's plant, or shortage of or inability to obtain necessary labor, raw materials, or transportation ("Force Majeure"). Any delay in the performance by either party under this Agreement shall be excused if and to the extent the delay is caused by the occurrence of a Force Majeure, provided that the affected party shall promptly give written notice to the other party of the occurrence of a Force Majeure, specifying the nature of the delay, and the probable extent of the delay, if determinable.

Following the receipt of any written notice of the occurrence of a Force Majeure, the parties shall immediately attempt to determine what fair and reasonable extension for the time of performance may be necessary. The parties agree to use reasonable commercial efforts to mitigate the effects of events of Force Majeure.

No liabilities of any party that arose before the occurrence of the Force Majeure event shall be excused except to the extent affected by such subsequent Force Majeure.

13. GOVERNING LAW

This Agreement shall be governed by and interpreted in accordance with the laws of the State of Illinois, excluding its choice of laws rules.

14. ENTIRE AGREEMENT

This Exhibit C3 and the Fuel Tech Proposal attached to it constitute the entire agreement between the parties and can be modified only in writing signed by authorized representatives of each of the parties..

INDECK KEYSTONE ENERGY, LLC.
5340 FRYLING ROAD, KNOWLEDGE PARK
ERIE, PA 16510-4672 U.S.A.
PHONE 814-452-6421 – FAX 814-897-1089

February 5, 2016 (F)

Stanley Consultants (SC)
8000 s. Chester Street, Suite 500
Centennial, CO 80112

Attention: Mr. John Solan, PE
303-649-7830
Subject: Low NOx Burners
University of Alaska Fairbanks, Alaska
Indeck Inq. No. 2015-111, G.O. #s 170-70 (Unit 3) & 1566 (Unit 4)

Dear Mr. Solan,

Thank you for your inquiry to have Indeck Keystone Energy (Indeck) provide low NOx burners for the two (2) Keystone package boilers originally furnished to the University of Alaska on our shop orders GO# 170-70 (in the year 1970) and GO# 1566 (in the year 1985) under our old name of Zurn Energy Division. Please note that we were purchased by Indeck Power Equipment Company of Wheeling, IL and renamed Indeck Keystone Energy effective September 8, 2004. We were formerly known as Keystone Energy, Aalborg Industries-Erie, Zurn Energy Division, and Erie City Iron Works. As the OEM, we have the original performance records and drawings for these boilers. Please note that the descriptions, sizes, etc. of the items listed herein are preliminary and may change in the final design and that no boiler performance guarantees are offered. We are pleased to quote the following:

1. Overview

Based on the original boiler information and new #2 fuel oil analysis summarized in the table below, Indeck is to provide preliminary and budgetary (not valid for purchase) pricing for supplying a new low NOx burner for each of the two (2) Indeck Keystone package boilers firing No 2 fuel oil with fuel analysis as shown in the table below.

No.	Item	Boiler #3 – GO 170-70 19M	Blr #4 – GO 1566 20M
1.1	Boiler Rating at MCR (max continuous rating)	100Kpph, 700#DP, 600# OP 750F	100Kpph, 750#DP, 610# OP, 750F
1.2	Air/flue gas flow config	FD fan – boiler - stack	Slncr- FD fan- Stm coil- AH- Blr- AH- stack
1.3	Original burner	32" SAO-MJ (#2 & #6 oil, future NGas)	34" SAOH (#4 Oil)
2.1	2016 #2 "Go by" Fuel Oil Analysis – Ref: Stnly Cnsltnts's e-mail of Jan 06-2016 & telephone call of Jan 21, 2016 to use 0.10 for the fuel bound N2 content		
2.2	C (Carbon)	85.17 % by weight	85.17 % by weight
2.3	H2 (Hydrogen)	14.33	14.33
2.4	O2 (Oxygen)	0.00	0.00
2.5	N2 (Nitrogen) (FBN)	0.10	0.10
2.6	S (Sulfur)	0.40	0.40
2.7	CL (Chlorine)	0.00	0.00
2.8	H2O (Water)	0.00	0.00
2.9	V (Vanadium)	0.00	0.00
2.10	Ash	0.00	0.00
2.11	Total	100.00	100.00
2.12	Fuel oil pressure req'd	150 psig at inlet to fuel piping train	150 psig at inlet to fuel piping train
2.13	Fuel oil atomizing req'd	150 psig steam / 100 psig air at inlet	150 psig steam / 100 psig air at inlet

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2. Low NOx Burner Equipment Description

2.1 Scope and Emissions

Each low NOx burner will be designed to fire #2 fuel oil only and will come with propane gas-electric ignitor, windbox, and miscellaneous field switches and flame scanning equipment. Also provided is a #2 fuel oil valve train and a PLC based burner management system (BMS) control panel. The package burner is factory preassembled to the maximum extent and is to be field installed to the existing boiler front wall.

The low NOx burners offered here may be operated with the existing boiler force draft (FD) fans with some possible shortness of full MCR steam rating due to the settings of the existing equipment. If lower NOx levels are desired, these FD fans must be replaced with new FD fans and motors designed to allow for induced flue gas recirculation (FGR) from the boiler flue gas outlet. Optional pricing for these FD fans with FGR capability is provided. Below is a summary of the predicted emissions from the existing burners, new low NOx burners with out FGR, and new low NOx burners with FGR. Note that the emissions listed below are predicted and not guaranteed as the #2 fuel analysis as shown in Section 1 above is only a "go-by" at this time with a fuel bound nitrogen (FBN) of 0.10%. If a fuel analysis with an accurate and lower FBN is provided to Indeck, then the NOx emissions listed below will change and most likely be lowered.

No.	**Item**	**Original Zurn Burner (Est) (based on 0.10 FBN & corrected to 3% O2 on a dry basis)**	**Low NOx burner w/o FGR at 100% MCR only at steady state (based on 0.10 FBN & corrected to 3% O2 on a dry basis)**	**Low NOx burner w FGR at 100% MCR only at steady state (based on 0.10 FBN & corrected to 3% O2 on a dry basis)**
1	**Boiler #3 – GO 170-70 19M** (FD fan – boiler – stack)			
1.1	NOx	1.0 to 1.2 lb/MMBtu (750 to 900 ppm)	0.28 lb/MMBtu (apprx 220 ppm)	0.18 lb/MMBtu (apprx 140 ppm)
1.2	CO	0.16 lb/MMBtu (apprx 210 ppm)	0.10 lb/MMBtu (apprx 130 ppm)	0.10 Lb/MMBtu (apprx 130 ppm)
1.3	PM	N/A	0.05 gr/scf average over 3 hours	0.05 gr/scf average over 3 hours
1.4	Opacity	20%	20% average over 6 minutes	20% average over 6 minutes
2	**Boiler #4 – GO 1566 20M** (Slncr- FD fan- Stm coil- AH- Blr- AH- stack)			
2.1	NOx	1.0 to 1.2 lb/MMBtu (750 to 900 ppm)	0.40 lb/MMBtu (apprx 310 ppm)	0.22 lb/MMBtu (apprx 170 ppm)
2.2	CO	0.16 lb/MMBtu (apprx 210 ppm)	0.10 lb/MMBtu (apprx 130 ppm)	0.10 Lb/MMBtu (apprx 130 ppm)
2.3	PM	N/A	0.05 gr/scf average over 3 hours	0.05 gr/scf average over 3 hours
2.4	Opacity	20%	20% average over 6 minutes	20% average over 6 minutes

Note 1: No boiler performance guarantee using the new low NOx burners is offered. Any emission guarantees will be for NOx and CO only at 100% of the burner MCR Btu heat input corrected to 3% O2 based on firing the No 2 Fuel Oil analysis as provided to Indeck, a fully welded furnace construction (steam drum to mud drum along the full furnace length), and a service technician required for start-up and adjustments.

Note 2: The above listed predicted emissions are at 100% MCR only and are based on the furnace wall tubes forming a gas tight wall baffle to prevent short circuiting of the furnace flue gases to the boiler gas

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outlet. The customer may have to seal weld the tangent furnace walls in the “valley” formed where the tangent tubes touch in order to meet any emissions guarantee. This seal weld is to run from steam drum to mud drum for every tube to tube tangent point along the full length of the furnace to obtain the gas tight wall baffle. Seal welding the tubes must be done with care to avoid weld “blow through” of these tubes. If the wall thickness of these furnace wall tubes is too thin for welding, then these tubes should be replaced with thicker wall tubes. Any emission guarantees offered exclude background emissions present in the ambient air used for combustion.

Note 3: Testing for emission guarantees shall be run within thirty (30) days after the equipment has been installed and operated. The Customer, at Customer’s expense, shall make all preparations and furnish all operating and testing personnel and equipment and incur all expenses connected with such tests and shall give to Seller at least fifteen (15) days notice of the date or dates on which tests will be made. An Indeck trained service engineer (not included but may be hired separately) shall fine tune the burner as required and observe the operation of auxiliary equipment to assure that the emission guarantees will be met, prior to testing. Indeck's representative will have access to the records at all times and the tests will be conducted in a manner to ensure that the specified performance conditions are being maintained. The Customer shall take samples of the fuel oil during the emission test and have its nitrogen content measured by an independent test laboratory. Material, labor, fuel, utilities, temporary test equipment, electronic data logger /recorder, and supervision to conduct performance test shall be furnished by Buyer Customer to provide Indeck with a complete copy of all test results and data.

Emission test (if guaranteed) shall be performed by others in accordance with the Federal EPA Code of Federal Regulations (CFR 40 Part 60 Appendix A) which states the following test methods: NOx = Method 7, CO = Method 10, VOC / UBHC = Method 25, Particulate = Method 5. If a local governing authority has different testing criteria, it shall be provided to Seller for review and comment. The determination of the fuel or fuels high heating value must be made in accordance with the applicable ASTM Standard.

The equipment shall be considered accepted if tests show that the emissions guarantees have been fulfilled, or if the equipment is tested within the specified period. In case of the failure to meet the emission guarantees, Indeck , subject to Indeck’s General Conditions of Sale – Parts, reserves the right to repair, change, or replace, on a straight time basis, the equipment furnished. All labor to remove, repair or replace, and reinstall any and all equipment provided by Indeck including all freight to and from Customer will be by Customer.

Note 4: The Seller or its representative will not be responsible for operation or maintenance of the equipment provided under this contract at any time including prior to or during acceptance testing.

2.2 Burner

2.2-1 Burner Description

Each burner will be fabricated using standard stainless and mild steel components, complete with the following sub-assemblies, mounted in the windbox

- One (1) fixed air register
- One (1) burner front hub assembly, complete with observation port and flame scanner swivel mounts
- One (1) swirling diffuser assembly
- One (1) low steam usage atomizing oil gun assembly, manually retractable
- One (1) atomizer coupling block assembly

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One (1) ignition assembly complete with gas-electric ignitor, high tension cable and connector and high energy transformer in a NEMA 4 enclosure
One (1) burner guide ring to be welded on the boiler front plate to align the burner to the burner opening (shipped loose)
One (1) throat former for installation of boiler front wall refractory at the burner opening (shipped loose)
One (1) set of burner tools (shipped loose)
One (1) ignitor flexible hose, stainless steel body, NPT
One (1) oil flexible hose, stainless steel body, NPT
One (1) atomizing steam flexible hose, stainless steel body, NPT
One (1) flame scanning equipment
One (1) lot of the following miscellaneous field switches mounted to the windbox
  One (1) combustion low air flow switch (Dwyer)
  One (1) purge low air flow switch (Dwyer)
  Two (2) boiler drum steam high pressure switches (Ashcroft)
  One (1) furnace high pressure switch (Dwyer)

2.2-2 **Burner Features**

Some of the standard design features of the burner are:

Flame stability at low excess air rates to help provide for reliable and energy efficient boiler operation
High turndown ratios for wide range of boiler operation
Axial parallel air flow to help control the flame envelope and provide even heat flux
Known flame length and diameter to suit furnace firing lane and minimize flame impinging on boiler tubes or furnace walls
Air registers to provide internal staging of the combustion process to help reduce NOx formation
Combustion air passes through a fixed air register design with no moving parts to help reduce operator attention
A strong flame front established just off the face of the diffuser which helps the burner refractory throat to remain cool thus minimizing the replacement of the burner refractory throat. The flame front established near the face of the diffuser remains relatively stable and with minimal movement during changes in the firing rate thus helping to provide a stable flame for scanning and more reliable burner operation
Flame scanner swivel mount for ease of "sighting" of flames, mounted on the burner front plate
Atomizer which uses low amounts of steam or air typically on a lb per of fuel oil basis.
Atomizer coupling block provided with mechanical safety interlocks with integral shut-off valves to prevent oil and atomizing steam flow if the oil gun is inadvertently withdrawn from the burner while oil firing
Atomizer coupling block provided with a gas flap to allow removal of the oil gun assembly while the boiler is firing gas fuel
Gas-electric ignitor which operates only through the cycle to light-off the main fuel and is fixed in the burner and terminates behind the diffuser thereby eliminating retraction mechanisms and associated limit switches and thus minimizing boiler front components and maintenance.
Heavy gauge construction of all components for ruggedness and durability during installation and servicing

2.2-3 **Burner Miscellaneous Data**

Burner Location	Indoors, non-hazardous
Plant Elevation	436 ft asl
Power Supply Available	120V/1Ph/60Hz

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	480V/3Ph/60Hz
Instrument Air Available	60 psig (minimum)
Valve Train Construction	NFPA31 (oil)
Surface Preparation and Painting	Manufacturer standard
Quality Control	Manufacturer standard

2.2-4 Burner Specifications

Number of Burners per Boiler	One (1)
Fuel Firing per Burner	
Heat Input - MMBtu/hr	150 Unit 3 / 136.5 Unit 4
Turndown	6 to 1
Pressure at Burner	150 psig oil and steam
Excess Air at MCR	15%
Flue Gas Recirculation Rate at MCR	15%

2.2-5 Gas Electric Ignitor Specifications

Number of Ignitors per Boiler	One (1)
Gas Firing	
Heat Input	500,000 btu/hr
Pressure at Burner	1 psig (approx)
Type	Class 3
Operation	Intermittent

2.5-6 Project Documents

Supplier to provide a submittal consisting of packaged burner general arrangement drawing, valve train schematics, electrical schematics, and one (1) copy of supplier's instruction manual

2.3 Windbox

Each boiler will be provided with one (1) windbox, non-insulated, fabricated of ASTM A-36 carbon steel plate, and complete with required structural framing, support legs, access door, lifting lugs, and straightening devices for balancing air flow distribution to the burner. The windbox will be provided with an inlet opening for connection to the combustion air duct. The windbox will be painted with manufacturer's standard. The windbox is to be seal welded to the boiler front plate in the field by the Customer. The windbox is to be field insulated by the Customer.

3. Fuel Piping Train

Each boiler will be provided with the following valve trains shop mounted on the windbox to the maximum extent feasible, and will include valves, piping specialties and instrumentation as specified below. All electrical components will be wired to a NEMA 4 terminal box. Unless otherwise noted, the interface points are at the inlet of the supply manual shut-off valves and the discharge of vent, and drain valves. Valve trains will be fabricated using Schedule 80 ASTM A-106 Grade B seamless steel pipe and 3,000 lb. threaded fittings. Valve trains will be painted with manufacturer's standard. Insulation and lagging is not included.

3.1 One (1) ignitor gas pilot train, consisting of:

- 1- Supply manual shut-off valve, brass body, NPT
- 1- Gas strainer with basket "Y" type, cast iron body, NPT
- 1- Gas pressure regulating valve, cast iron body, NPT
- 2- Automatic safety shut-off valves, solenoid type, aluminum body, NPT (Asco)

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1- Automatic safety vent valve, solenoid type, aluminum body, NPT (Asco)
1- Ignitor manual shut-off valve, brass body, NPT
1- Ignitor pressure gauge, 2.5 in dial, with isolation valve

3.2 **One (1) No. 2 fuel oil train, consisting of:**

1- Supply manual shut-off valve, brass body, NPT
1- Oil strainer with basket "Y" type, cast iron body, NPT
1- Oil pressure regulating valve, cast iron body, NPT
1- Supply pressure gauge, 4 in dial, with isolation valve
1- Low oil pressure switch (Ashcroft)
1- Oil flow control valve, vee-ball type, carbon steel body, 150# RF, with low fire limit switch, pneumatic actuator and I/P positioner
1- Supply automatic safety shut-off valve, carbon steel body, NPT, pneumatically operated, with proof of closed limit switch
1- Manual pressure relief valve, brass body, NPT
1- Supply automatic safety shut-off valve, carbon steel body, NPT, pneumatically operated, with proof of closed limit switch
1- Burner manual shut-off valve, brass body, NPT
1- Burner check valve, bronze body, NPT
1- Burner pressure gauge, 4 in dial, with isolation valve
1- Burner flexible hose, stainless steel, NPT

3.3 **One (1) steam/compressed air train, for fuel oil atomization, consisting of:**

1- Supply manual shut-off valve, carbon steel body, NPT - steam
1- Supply manual check valve, carbon steel body, NPT - steam
1- Supply manual shut-off valve, carbon steel body, NPT - air
1- Supply manual check valve, carbon steel body, NPT - air
1- Strainer with basket "Y" type, carbon steel body, NPT
1- Steam trap, carbon steel body, NPT
1- Steam trap isolation valve, carbon steel body, NPT
1- Supply pressure gauge, 4 in dial, with isolation valve
1- Low pressure atomizing medium switch (Ashcroft)
1- Pressure regulating valve, carbon steel body, NPT
1- Automatic shut-off valve, carbon steel body, NPT, pneumatically operated
1- Burner manual shut-off valve, carbon steel body, NPT
1- Burner check valve, carbon steel body, NPT
1- Low auxiliary pressure atomizing pressure switch (Ashcroft)
1- Burner pressure gauge, 4.5 in dial, with isolation valve
1- Burner flexible hose, stainless steel, NPT
1- Oil gun purge manual shut-off valve, carbon steel body, NPT
1- Oil gun purge check valve, carbon steel body, NPT

3.4 **One (1) instrument air train to pneumatic users in the valve trains**:

1- Supply manual shut-off valve, ball type, carbon steel body, NPT
1- Supply pressure gauge, 4 in dial, with isolation valve
1- Low instrument air pressure switch (Ashcroft)
1- Lot of manual shut-off valves (one per user)

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4. Burner Management System (BMS) Control Panel

Each boiler will be provided with one (1) burner management system consisting of one (1) wall-mounted, NEMA 4 enclosure which uses First-Out Indication to give extended trouble shooting information to operators and technicians. The PLC directs all of the BMS functions required for automatic start up, shutdown, and on-line supervision of the combustion process. Logic implemented in the PLC includes: permissive supervision, furnace purge, master fuel trip, ignition fuel valve management, main fuel valve management, interlock supervision, shutdown, post-purge, critical I/O testing and watchdog timer handshaking. The panel will be built to meet the requirements of NFPA-85 and will house the following:

1- Circuit breaker
1- Allen Bradley programmable logic system for burner management system relay and timing logic, consisting of the CompactLogix processor, Ethernet communications, EEPROM memory back up, power supply, and 120VAC discreet input and output modules
1- External watchdog timer
1- Alarm horn
4- Drum level relays (Warrick)
1- Lot of contacts for interfacing with combustion control system: go to purge, go to low fire, released to modulate
1- Operator interface including first-out annunciation

A detailed sequence of operating description for burner start/shutdown control and operating control, in accordance with NFPA 85, "Boiler and Combustion Systems Hazards Code" will be provided.

5. Scope by Customer

Customer shall be responsible for the receipt, unloading, and installation of the burner and all auxiliary equipment furnished by Indeck plus the supply and installation of any additional components or materials required for a complete operable installation. Items to be supplied by Customer shall include but not necessarily be limited to the following:

- Foundations, shims, sole plates, and lubrication pads for expansion
- Boiler drum level probes
- Boiler auxiliary drum level cut-out switch
- Boiler drum level bypass pushbutton station
- Fan motor starter, control centers, and any switchgear
- Oil pump set with regulated oil pressure
- F. D. fan/motor and silencer
- Fan motor starter
- Combustion air duct between the F. D. fan discharge and windbox
- Flue gas recirculation (FGR) duct from economizer outlet to air/FGR mix box inlet
- Combustion control field devices not specifically included
  - F. D. fan inlet vane damper with actuator
  - Combustion air flow meter
  - Fuel oil flow meter
  - Stack oxygen probe/transmitter for oxygen trim
- FGR system components consisting of, but not limited to:
  - FGR ducts, dampers, and expansion joints
  - Air/flue gas recirculation mixing box
  - Flue gas recirculation mixing box inlet damper, mounted on the combustion air inlet, with pneumatic actuator with I/P positioner, for controlling FGR rate below 100% load
  - Flue gas recirculation damper, mounted in the FGR duct, manually set and locked during start-up, for setting FGR rate at 100% load

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Feedwater field control devices
Boiler combustion control system
Purge air piping for flame scanners (approximately 10 scfm of plant air at 8 in wg above windbox pressure)
Draft controls if stack height is more than 50 feet above ground or common stack
Plant master (load) signal to each boiler
Insulation
Boiler front wall refractory at the burner opening
Technical information required to proceed including:
confirmation of the burner design basis specified in Section 1 & 2 above
Design, supply, and installation of any ductwork and any modifications
Design, installation, and / or modifications of any foundations
Seal welding of the furnace boiler wall tubes
Supply or installation of any electrical wiring, instruments, piping, gauges, etc.
Changes to the boiler refractory front wall and burner throat refractory may have to be altered or removed and replaced to accommodate the depth of the new Low NOx burners.
Field erection, installation, management
Field Service Consultant – this is not included in Indeck's bid but can be hired on a per diem basis per Indeck's Field Service Terms and Conditions
Insulation and lagging of all ducts and piping and FD Fan (if required)
Supports for all ductwork including air/FGR mixing box
Supports for fan silencer
All Field Piping and wiring, including the interconnecting the piping rack to the burner front
Instrumentation not specifically included
Interconnecting piping, tubing, and wiring to and from all IKE supplied equipment
Combustion controls
DCS & PLC configuration, testing, & commissioning
Field instruments & boiler trim for fuel, air, flue gas, water, & steam
Welded furnace construction is required for a CO guarantee as the tangent tube design will result in furnace bypass that will result in high CO emissions
Field installation of all equipment and all field modifications required to install this equipment

6. Force Draft (FD) Fans (Option)

Should flue gas recirculation (FGR) be required, the existing FD fans and motors will need to be replaced on both boilers. Fans shall be Arangement 7 SWSI center hung complete with 1800 RPM TEFC motor, VIV for flow control, fresh air/FGR mixing box with opposed blade damper, and inlet silencer for approximately 85 DBA at 3 ft (excludes noise from other equipment). All duct work and any modifiction there of to install theses fans including the design and installation or modification to the fan foundations is by Customer. The motor is sized for 3/60/460V. Any associated transformers are by others.

7. Field Service - Option

Indeck can provide a Field Service Consultant during installation and start-up including operator training at the per diem rate in effect at time of request, in accordance with Indeck's Service Terms. **No jobsite services are included in our base bid.**

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Commercial Terms

1. Total lot preliminary and approximate price not valid for purchase for the burner equipment as described above in Items 1 through 5 for:

1.1 Boiler #3 (GO 170-70) is $ 419,484.00 Approximate ship date is 36 Weeks

1.2 Boiler #4 (GO 1566) is $ 444,039.00 Approximate ship date is 36 Weeks

Approximate ship date for both boilers if ordered simultaneously is 40 weeks.

2. Total lot preliminary and approximate price not valid for purchase for the fan equipment as described above in Item 6 for:

2.1 Boiler #3 (GO 170-70) is $ 198,872.00 Will ship with burner

2.2 Boiler #4 (GO 1566) is $ 187,755.00 Will ship with burner

Pricing is net FOB shipping point and does not include any freight.

Freight to be paid in full prior to shipment or to be arranged by Customer or sent Collect using Customer's shipping company.

Approximate ship dates shown are after receipt of an acceptable order and receipt of payment in accordance with the payment terms shown below and subject to shop load and material availability at time of order.

Indeck's pricing does not include any sales or use taxes or fees or duties.

Pricing is valid for 15 days from the date of this quote and subject to Indeck's attached standard General Conditions of Sale – Parts which shall solely govern any order for the above quoted items.

Payment Terms

Payment terms will be progress based on the following milestone schedule pending credit review at time of order:

25% upon confirmation of an acceptable order, Net 0
25% upon supply of submittal documents
25% upon release to purchase and fabricate, Net 0
15% prior to shipment, Net 0
10% prorated at shipment or offer to ship, Net 30.

Please note that this order will be shipped once payment has been received in accordance with the payment terms above and if there is no delinquent balance on any other order.

Payment may be made via Automatic Clearing House Payments (ACH) via:

1. American Enterprise Bank's ABA (Routing):	# 071925541
2. American Enterprise Bank Account Number:	# 1015278
3. Account Name:	Indeck Keystone Energy, LLC

When the equipment is ready for shipment and shipment is deferred beyond the contract shipping date through no fault of the Seller, payment, per the payment terms above, shall nevertheless be due on the contract shipping date.

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We thank you for allowing us this opportunity to serve you. Please review our offer and contact me should you have any questions

Sincerely,

Philip J. Meehan *February 5, 2016 (F)*

Philip J. Meehan
Manager, Engineered Components
Indeck Keystone Energy
5340 Fryling Rd Erie, PA 16510
Phone 814-464-1202 Fax 814-897-1089 Toll Free 1-800-322-5995 e-mail: pmeehan@indeck-keystone.com

Providing parts and service for Erie City Iron Work Boilers
Zurn Energy Division Boilers
Aalborg Ind Erie –Land Based Boilers
Keystone Energy (Division of Erie Power Technologies, Inc)

From: Rubino, Joe [RubinoJoe@stanleygroup.com]
Sent: March 17, 2016 10:08 AM
To: Julie Ackerlund; Courtney Kimball
Cc: Pacini, Lain; Solan, John; Rubino, Joe
Subject: Latest Information from Indeck

Julie/Courtney –

We finally heard back from Indeck late yesterday on the revised emission estimates using the updated fuel nitrogen content from the 2001 fuel analysis. Before giving the emission estimates they commented that while the test methods shown on the lab report are the appropriate methods, the 48 ppm FBN (fuel bound nitrogen) is equivalent to 0.0048% FBN which is well below the typical FBN level of 0.02% for #2 fuel oil. Also, the sulfur is relatively high. Typically, the nitrogen and sulfur in the fuel oil generally trend the same way meaning low nitrogen fuel often has low sulfur, and high nitrogen fuel usually has high sulfur. If we needed to get emission guarantees, Indeck recommends a current fuel analysis be provided.

Below are the predicted emissions using the existing burners (supplied under the old name of Zurn) and also a low NOx burner with and without FGR. The predicted emissions for the Zurn burners are based on using 0.03 FBN while the predicted emissions for the low NOx burners are based on 0.02 FBN. These emission rates have been corrected to 3% O2 on a dry basis.

No.	**Item**	**Original Zurn Burner (based on 0.03 FBN)**	**Low NOx burner w/o FGR at 100% MCR (based on 0.02 FBN)**	**Low NOx burner w/ FGR at 100% MCR (based on 0.02 FBN)**
1	Boiler #3	NOx=0.30 lb/MMBtu (approx 230 ppm)	NOx = 0.20 lb/MMBtu (approx 155 ppm)	NOx = 0.10 lb/MMBtu (approx 80 ppm)
2	Boiler #4	NOx=0.51 lb/MMBtu (approx 400 ppm)	NOx = 0.34 lb/MMBtu (approx 260 ppm)	NOx = 0.16 lb/MMBtu (approx 130 ppm)

The estimates for the original burners are getting closer to what has been historically used for emission rate calculations for each boiler. However I don't think it is prudent to use one fuel analysis to gauge the accuracy of what has been used for previous permitting and reporting. As far as this current BACT analysis, what this continues to suggest is that use of a Low NOx burner without FGR will not improve on current potential emission rates. I do think it makes sense to run the economics for the LNB+FGR scenario using a reduction from 0.2 lb/MMBtu to either 0.1 or 0.16. John is in the process of confirming that the cost information provided previously can still be used with these estimates, so as soon as we know, we can finalize those tables and send them over for review.

Let me know if you have any questions and if you want to discuss further. Thanks.

Joe

Description: Description: Description: Email Signature

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Joe Rubino | **Environmental Services Department Manager**
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"Creativity can solve almost any problem. The creative act, the defeat of habit by originality, overcomes everything."

INDECK KEYSTONE ENERGY, LLC.

Indeck Keystone Energy, LLC

Consultant Time & Charges - Domestic

Date: 3/29/2016

Customer: University of Alaska

Location: Fairbanks, AK

2015-111

Customer Contact: John Solan

Customer P. O. Number: Later

Date	Day	Personnel	Activities	S.T. Hrs.	O.T. Hrs.	S.T. $	O.T. $	Expenses
	Mon	1	Travel	8.0	0.0	$1,680.00	$0.00	$400.00
	Tue	1	On site - boiler inspection	8.0	2.0	$1,680.00	$630.00	$400.00
	Wed	1	On site - boiler inspection	8.0	2.0	$1,680.00	$630.00	$400.00
	Thu	1	On site - boiler inspection	8.0	2.0	$1,680.00	$630.00	$400.00
	Fri	1	Travel	8.0	0.0	$1,680.00	$0.00	$400.00
			Totals:	40.0	6.0	$8,400.00	$1,890.00	$2,000.00

Labor Total:	$10,290.00	Estimated
Travel	$1,500.00	Estimated
Expenses Total	$2,000.00	Estimated
Sub Total:	$13,790.00	Estimated
Tax	$0.00	Estimated
Grand Total	**$13,790.00**	Estimated

All amounts in US dollars.

Rates:
$1680/day = $210.00/hour for S.T.
$315/hour for O.T., Mon - Sat $420/hour Sun & holidays
$400/day for car rental, lodging and living expenses

Rubino, Joe

To: Solan, John
Subject: RE: #3 Boiler Low NOx Burner & FGR

From: "**Doug Smith**" <dsmith@haskellcorp.com>
Date: Tue, Apr 5, 2016 at 5:34 PM -0700
Subject: #3 Boiler Low NOx Burner & FGR
To: "Solan, John" <SolanJohn@stanleygroup.com>
Cc: "Terry Corrigan" <TCorrigan@haskellcorp.com>

John,

We looked at the Low NOx Burner replacement and FGR & FD Fan work. Our estimate with a +/- 25% accuracy is

ITEM	DESCRIPTION	MANHOURS	LABOR $	MATL $	SUBCON $	TOTAL COST
3-1 Total	**#3 BOILER LOW NOX BURNER REPLACEMENT**	**559**	**$ 69,820**	**$ 14,313**	**$ 38,875**	**$ 123,008**
3-2 Total	**#3 BOILER FGR DUCT & FD FAN REPLACEMENT**	**810**	**$ 101,250**	**$ 15,400**	**$ 3150**	**$ 119,800**
	Grand Total	**1571**	**$ 196,383**	**$ 33,563**	**$ 42,813**	**$ 272,758**

This assumes that the procurement of the burner, fan, and DCS modifications are by Owner.

Doug Smith
Construction Manager
Haskell-Davis Joint Venture
UAF CHPP Project
814 Alumni Drive
Fairbanks, AK 99706
Office (907) 474-7802
Mobile (907) 322-7779
dsmith@haskellcorp.com

BACT Analysis Support for EU IDs 19, 20, and 21, Small Diesel-fired Boilers

From: Courtney Kimball [ckimball@slrconsulting.com]

Sent: December 10, 2015 12:16 PM

To: Julie Ackerlund; Jamie Brewer

Subject: FW: Economic Analyses for UAF

Attachments: Scrubber - WM 2094W Boilers PM2.5.xlsx

Courtney Kimball
Senior Engineer
SLR International Corporation

Direct: 907-452-2280

Office: 907-452-2252

Fax: 907-452-2256

Email: ckimball@slrconsulting.com

543 3rd Avenue, Suite 235, Fairbanks, AK, 99701, United States

www.slrconsulting.com

From: Rubino, Joe [mailto:RubinoJoe@stanleygroup.com]
Sent: December 10, 2015 08:03
To: Courtney Kimball
Cc: Pacini, Lain; Stevenson, Cindy; Solan, John; Rubino, Joe
Subject: Economic Analyses for UAF

Hi Courtney –

Now moving on to BIRD Boilers –

1) Scrubber for $PM_{2.5}$ Emissions –

- The vendor providing the cost estimate is Proctor Sales Inc.
- The vendor indicated that although a scrubber would be technically feasible for this size of boiler, it is not typically applied due to high capital cost.
- We assumed a 99% reduction in emissions, which is conservative for the cost per ton calculation.
- Just using the capital cost of $300K, we are able to show that the cost per ton is prohibitive. See attached.

2) Low NO_X Burners for NO_X Emissions –

- The vendor providing cost estimate and emissions information is Proctor Sales Inc.
- The vendor indicated that the lowest he could estimate on emissions is 100 ppmv when burning fuel oil.
- Using that projected concentration, we calculated lb/hr and ton/year emission estimates of 1.41 lb/hr (each boiler) and 13.87 tons/year (for combined operating hour limit of 19,650 hours per year).
- The current emission limit is 8.8 tons per year which is much lower than what was calculated for the LNB installation.
- I recommend crafting language in the technical feasibility section that indicates current NO_X emissions cannot be lowered from the current permit limit and thus LNB would not be feasible. Let me know what you think. I can assist with the specific language.

Let us know of any questions. Traveling back to Denver today and back in the office on Friday. Next emails will switch to GVEA sources. Thanks.

Joe

This image cannot currently be displayed.

Joe Rubino | **Environmental Services Department Manager**

8000 South Chester Street Suite 500 | Centennial, Colorado 80112

303.925.8282 (phone) | 515.450.3563 (mobile) | 303.799.8107 (fax)

rubinojoe@stanleygroup.com

www.stanleyconsultants.com

"Creativity can solve almost any problem. The creative act, the defeat of habit by originality, overcomes everything."

Rubino, Joe

From:	Rubino, Joe
Sent:	Monday, December 21, 2015 12:32 PM
To:	Rubino, Joe
Subject:	RE: Options for reducing air emissions from two Weil-McLain Boilers

---

From: Troy Nibert [mailto:tnibert@gopsi.com]
Sent: Wednesday, November 04, 2015 5:04 PM
To: Stevenson, Cindy <StevensonCindy@stanleygroup.com>
Subject: RE: Options for reducing air emissions from two Weil-McLain Boilers

You are correct. Thanks

PROCTOR SALES INC
www.gopsi.com

Troy Nibert
Sales Representative
Anchorage, AK Location
tnibert@gopsi.com
Cell: 907-223-8830
Main: 907-562-2608
Fax: 907-562-0503

From: Stevenson, Cindy [mailto:StevensonCindy@stanleygroup.com]
Sent: Wednesday, November 04, 2015 1:27 PM
To: Troy Nibert <tnibert@gopsi.com>
Subject: RE: Options for reducing air emissions from two Weil-McLain Boilers

Thanks for confirmation on the $300 K, and for the boilers should I assume the $15 K covers installation, freight, startup and training?
For the boilers, there are three locations:
University of AK at Fairbanks,
Golden Valley Electric Association – North Pole facility and
Golden Valley Electric Association – Zehnder facility (Fairbanks).

Sorry to be pushy, just want to get it right.

From: Troy Nibert [mailto:tnibert@gopsi.com]
Sent: Wednesday, November 04, 2015 4:19 PM
To: Stevenson, Cindy <StevensonCindy@stanleygroup.com>
Subject: RE: Options for reducing air emissions from two Weil-McLain Boilers

I need to know where the products are located before I can give you a price. Estimate, a weeks' worth of work you could safely budget 15K for install. Yes, by my information 300K is a fair budget.

Troy Nibert
Sales Representative

PROCTOR SALES INC www.gopsi.com	Anchorage, AK Location tnibert@gopsi.com Cell: 907-223-8830 Main: 907-562-2608 Fax: 907-562-0503

From: Stevenson, Cindy [mailto:StevensonCindy@stanleygroup.com]
Sent: Wednesday, November 04, 2015 1:08 PM
To: Troy Nibert <tnibert@gopsi.com>
Subject: RE: Options for reducing air emissions from two Weil-McLain Boilers

Thanks Troy!
Can you give me an estimate of installation, freight, startup and training?
Also – can you verify the $300,000 as a rough cost for the scrubber?

From: Troy Nibert [mailto:tnibert@gopsi.com]
Sent: Wednesday, November 04, 2015 4:05 PM
To: Stevenson, Cindy <StevensonCindy@stanleygroup.com>
Subject: RE: Options for reducing air emissions from two Weil-McLain Boilers

Hello Cindy, the Riello burner for WM 2094, burning 47.5 gallons per hour will run approximately $11,500 each, the smaller WM 688 burning 11.8 GPH is around $6,200 each. Both burners will provide you close to 100 PPM on NOx assuming +/- 10 PPM on either side. Please note these budget cost do not include install, freight, start up or training.

Your understanding is correct, scrubbers are not typically used in AK, they are more for large equipment and are very expensive.

Please advise if you need further clarification. Thanks

PROCTOR SALES INC www.gopsi.com	Troy Nibert Sales Representative Anchorage, AK Location tnibert@gopsi.com Cell: 907-223-8830 Main: 907-562-2608 Fax: 907-562-0503

BACT Analysis Support for EU ID 8, Large Diesel-fired Engine

From: Rubino, Joe [RubinoJoe@stanleygroup.com]
Sent: February 24, 2016 4:32 PM
To: Julie Ackerlund
Cc: Solan, John; Courtney Kimball
Subject: DPF on DEG Engine

Julie –

Our contact at Fairbanks Morse Engine (FME) has finally weighed in on the possibility of installing a diesel particulate filter on the DEG engine. First, they have been clear to state that **FME has never supplied a DPF with a new engine or for aftermarket use**, which explains why they have not provided a cost proposal**.** This implies that for this size engine, a DPF may not be commercially available. What does the BACT Clearinghouse suggest in this regard?

FME also indicated that regardless of what type of after treatment equipment is added to an existing exhaust system, the equipment should be sized such that it does not cause the total exhaust system backpressure to exceed the maximum allowable as stated by the OEM. The equipment should also be designed so that it is capable of operating within the expected temperature range.

The current backpressure limit for the UAF engine is 10" W.C. total system backpressure. We have not been provided and don't have specific data on what the DP across a DPF would be, but it is likely to be comparable to, if not more than, the existing SCR. John and I both think that given the SCR, the engine would operate very close to or higher than the backpressure limit, if a DPF was added.

From a technical feasibility standpoint, increased exhaust pressure can have a number of effects on the diesel engine, as follows:

- Increased pumping work
- Reduced intake manifold boost pressure
- Cylinder scavenging and combustion effects
- Turbocharger problems

At increased back pressure levels, the engine has to compress the exhaust gases to a higher pressure which involves additional mechanical work and/or less energy extracted by the exhaust turbine which can affect intake manifold boost pressure. This can lead to an increase in fuel consumption, PM and CO emissions and exhaust temperature. The increased exhaust temperature can result in overheating of exhaust valves. An increase in NO_X emissions is also possible due to the increase of engine load.

What are your thoughts on trying to argue that a DPF is not available and not technically feasible based on the information above?

Thanks.

Joe

Joe Rubino | Environmental Services Department Manager
8000 South Chester Street Suite 500 | Centennial, Colorado 80112
303.925.8282 (phone) | 515.450.3563 (mobile) | 303.799.8107 (fax)
rubinojoe@stanleygroup.com
www.stanleyconsultants.com

"Creativity can solve almost any problem. The creative act, the defeat of habit by originality, over-comes everything."

BACT Analysis Support for EU ID 27, Small Diesel-fired Engine

Rubino, Joe

From: Pomrenke, Erick <EPomrenke@NCPowerSystems.com>
Sent: Thursday, November 12, 2015 11:12 AM
To: Pacini, Lain
Subject: RE: UAF - 516 HP CAT C15 Genset

Follow Up Flag: Follow up
Flag Status: Completed

Lain,

Answers below for a standalone SCR – not a combined SCR / DPF system. Let me know if you need anything else.

Thanks

Erick

From: Pacini, Lain [mailto:PaciniLain@stanleygroup.com]
Sent: Thursday, November 12, 2015 6:48 AM
To: Pomrenke, Erick <EPomrenke@NCPowerSystems.com>
Subject: RE: UAF - 516 HP CAT C15 Genset

Eric,

If a stand-alone SCR is chosen. I have a couple of questions:

1. What kind of reagent is used? Ammonia or urea? UREA / DEF fluid (diesel exhaust fluid) same same

2. How much do catalyst replacements cost? The replacement bricks run about $115 each and it looks like the reactor as 87 so $10,000.00

3. How much would freight to Fairbanks run? The shipping for the last SCR package was $9,000 to $12,000 range.

Thank You,

Lain

From: Pomrenke, Erick [mailto:EPomrenke@NCPowerSystems.com]
Sent: Wednesday, November 11, 2015 12:05 PM
To: Pacini, Lain <PaciniLain@stanleygroup.com>
Subject: RE: UAF - 516 HP CAT C15 Genset

Lain,

Here are some basic pricing options for your requests.

C15 at UAF

1. DPF package with insulating blankets and Active DPF system FOB the factory $26,428.00

2. SCR system only with insulated blankets FOB the factory $107,120.00
3. SCRT system combined SCR and DPF FOB the factory $142,000.00

Installation is a big variable.
If you determine which option you want to go with we can move on to firm freight quotes, prints and possible installation estimates.

Thank you

Erick Pomrenke
NC POWER SYSTEMS
GENERATOR / COMPRESSOR
RENTALS AND SALES
1-907-786-7565 OFFICE
1-907-632-6700 CELL
1-907-786-7567 FAX

From: Pacini, Lain [mailto:PaciniLain@stanleygroup.com]
Sent: Wednesday, November 04, 2015 11:59 AM
To: Pomrenke, Erick <EPomrenke@NCPowerSystems.com>
Subject: UAF - 516 HP CAT C15 Genset

Eric,

Thank you for taking the time to speak with me today. Like I mentioned UAF is being asked to look into lowering their NOx and PM emissions and would like to know what aftermarket controls are available for their CAT C15 engine to reduce each pollutant. Just to follow up from our phone call I need to know the following:

1. You mentioned that SCR is possible. What would be to capital cost to install an SCR system on the unit?

2. You mentioned that a diesel particulate filter (DPF) is possible. What would be to capital cost to install a DPF system on the unit?

I know you mentioned a single box Tier 4 final upgrade option and that is good but I would really like to know the standalone costs of the control systems mentioned above. They may only need one or the other and not necessarily both.

Thank You,

Lain Pacini, Q.E.P.
Air Quality Department Manager
Stanley Consultants, Inc.
2658 Crosspark Rd., Suite 100
Coralville, IA 52241
319.626.5306 (phone)
319.626.3993 (fax)
www.stanleyconsultants.com

From: Courtney Kimball [ckimball@slrconsulting.com]
Sent: December 09, 2015 6:03 PM
To: Julie Ackerlund; Jamie Brewer
Subject: FW: Economic Analyses for UAF
Attachments: SCR - 500 HP Cat C15.xlsx; DPF - 500 HP Cat C15.xlsx

Courtney Kimball
Senior Engineer
SLR International Corporation

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Office: 907-452-2252
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Email: ckimball@slrconsulting.com
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From: Rubino, Joe [mailto:RubinoJoe@stanleygroup.com]
Sent: December 09, 2015 16:03
To: Courtney Kimball
Cc: Pacini, Lain; Stevenson, Cindy; Solan, John; Rubino, Joe
Subject: Economic Analyses for UAF

Courtney –

Next up is the ACEP Generator.

1. SCR for NOX emissions –

    a. The vendor providing cost information is NC Power Systems.
    b. We have assumed a standalone SCR unit which is not combined with a DPF.
    c. The reagent used is UREA or DEF (diesel exhaust fluid).

d. For catalyst replacements, the replacement bricks run about $115 each and the reactor has 87 bricks.
e. We took a midpoint for shipping charges which is in the range of $9,000 to $12,000.
f. For maintenance labor, we have estimated 1 hour per day based on the fact that the engine can only operate for half the year (4380 hours/yr). Then we cut supervisor labor hours in half and estimated operating labor at 1/3 of the maintenance hours.
g. We have email documentation from the vendor that indicates catalyst replacement is 30% of total equipment cost.

2. DPF for PM2.5 emissions -

a. The vendor providing cost information is NC Power Systems.
b. We have assumed a standalone DPF which is not combined with an SCR.
c. For onsite labor, since vendor indicated 1 to 2 days of install time, we assumed 16 man hours.
d. The existing silencer will be removed when installing DPF. For direct installation costs, the removal of existing silencer is covered by on-site labor hours. This is because one worker can remove the silencer when installing the DPF silencer.

Send us your questions as necessary. Thanks.

Joe

Joe Rubino | **Environmental Services Department Manager**
8000 South Chester Street Suite 500 | Centennial, Colorado 80112
303.925.8282 (phone) | 515.450.3563 (mobile) | 303.799.8107 (fax)
rubinojoe@stanleygroup.com
www.stanleyconsultants.com

"Creativity can solve almost any problem. The creative act, the defeat of habit by originality, over-comes everything."

Rubino, Joe

From: Greg Laemmer <glaemmer@miratechcorp.com>
Sent: Thursday, November 12, 2015 9:08 AM
To: Pacini, Lain
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Follow Up Flag: Follow up
Flag Status: Completed

Len,

See below.

Greg

MIRATECH – *Engineered to Perform™*

Greg Laemmer, Sales Manager, Central Region – Power Generation
MIRATECH, 420 South 145th East Avenue, Mail Drop A, Tulsa, OK 74108-1305
Primary Phone (Cell) +1.918.513.1252
Alternate Phone +1.918.794.0341
Fax: +1.918.933.6231

glaemmer@miratechcorp.com
www.miratechcorp.com

From: Pacini, Lain [mailto:PaciniLain@stanleygroup.com]
Sent: Thursday, November 12, 2015 9:41 AM
To: Greg Laemmer <glaemmer@miratechcorp.com>
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Hi Greg,

I had a couple of questions about the SCR system for engine NOx control:

1. How often does the catalyst need to be replaced? 5 years?

   There is no set answer. Replacement requirements are based on application, hours, fuel, engine operation, etc. For a standby unit like this- we don't talk about catalyst replacement. SCR systems are designed to be used- and we usually discuss catalyst replacement in terms of hours/year and other factors related to prime operation. This engine never really runs….

2. What is the reagent that would be used in the SCR? Ammonia or urea? Urea.

2. How much does a catalyst refill cost of something of this scale? Per above answer… but in general catalyst blocks make up ~30% of the system cost.

Thanks,

Lain

From: Greg Laemmer [mailto:glaemmer@miratechcorp.com]
Sent: Wednesday, November 04, 2015 3:06 PM
To: Pacini, Lain <PaciniLain@stanleygroup.com>
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Lain,

Please see attached proposal for a low temperature regen DPF.

I did some looking and I think I identified the Mitsubishi engine—but we would need to verify the model.
I used some operating assumptions and information from previously sized solutions to come up with the operating data for the engine (Mitsubishi is notoriously bad at providing emissions information.
With that- the raw PM value you provided seems far too low. So I used a value I felt was more realistic (higher) and sized a solution to reduce by 85%Installation of the DPF is fairly simple in this case as you are removing the existing silencer (assuming it's on the roof) and replacing it with the LTR DPF. I would estimate a day or two at most on site to install. (at this size- it should only take one well planned day)

Regarding SCR for this engine- A standard SCR solution for this engine would cost ~100K installed- which is likely twice the engine price, and is really not a viable solution.

Give me a call to discuss.

Greg

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Primary Phone (Cell) +1.918.513.1252
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Fax: +1.918.933.6231

glaemmer@miratechcorp.com
www.miratechcorp.com

From: Pacini, Lain [mailto:PaciniLain@stanleygroup.com]
Sent: Wednesday, November 04, 2015 12:40 PM
To: Greg Laemmer <glaemmer@miratechcorp.com>
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Greg,

Let me first say thank you for making contact. It is really appreciated. From our phone call I feel like we were able to narrow down some feasible (although probably not cost effective) control strategies for this diesel fired 400 kW emergency engine. It looks like the PM emissions performance on the Mitsubishi engine is 0.0022 lbs/hp-hr according to emission inventory data. I have attached a picture of the nameplate on the generator. Can you please address the following?

1. You mentioned that the cost is excessive for an aftermarket SCR on a 400 kW unit. How much capital would it cost to install one of your SCRs on the Generac unit mentioned above?

2. You mentioned that a diesel particulate filter (DPF) would be the least cost effective but best reduction option for PM. How much capital would it cost to install one of you DPFs on the Generac unit in question?

Thank you for your assistance.

Lain

From: Greg Laemmer [mailto:glaemmer@miratechcorp.com]
Sent: Wednesday, November 04, 2015 11:15 AM
To: Pacini, Lain <PaciniLain@stanleygroup.com>; Bob Konkel <bkonkel@miratechcorp.com>
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Lain,

Calling you now.

Greg

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Greg Laemmer, Sales Manager, Central Region – Power Generation
MIRATECH, 420 South 145th East Avenue, Mail Drop A, Tulsa, OK 74108-1305
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Alternate Phone +1.918.794.0341
Fax: +1.918.933.6231

glaemmer@miratechcorp.com
www.miratechcorp.com

From: Pacini, Lain [mailto:PaciniLain@stanleygroup.com]
Sent: Wednesday, November 04, 2015 11:14 AM
To: Bob Konkel <bkonkel@miratechcorp.com>; Greg Laemmer <glaemmer@miratechcorp.com>
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Bob,

Do you have a phone # for Greg Laemmer that I could use to make direct contact if necessary?

Thanks,

Lain

From: Bob Konkel [mailto:bkonkel@miratechcorp.com]
Sent: Tuesday, November 03, 2015 9:14 AM

To: Greg Laemmer <glaemmer@miratechcorp.com>
Cc: Pacini, Lain <PaciniLain@stanleygroup.com>
Subject: FW: Emissions Control - Generac 400 kW Emergency Genset

Greg,

I apologize for the delayed message. I thought I had sent this last week however I missed adding you to the note.

Will you please reach out to Lain at the Stanley Group below?

Thank you again for your help, much appreciated.

Bob

MIRATECH – *Engineered to Perform™*

Bob Konkel, Regional Sales Manager
Industrial / Off-Road
5380 Cottonwood Lane, Prior Lake, MN 55372
Primary Telephone: 952.836.6601

"Proudly making the EM Products since 1985"

bkonkel@miratechcorp.com
www.miratechcorp.com

From: Pacini, Lain [mailto:PaciniLain@stanleygroup.com]
Sent: Tuesday, November 03, 2015 9:11 AM
To: Bob Konkel
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Hi Bob,

I noticed that on the e-mail below that it looks like you may have forgot to cc Greg Laemmer. I have not heard from him yet but that may be because he did not know about our communications. Can you please get Greg in touch with me on the questions I posed below.

Thank You,

Lain

From: Bob Konkel [mailto:bkonkel@miratechcorp.com]
Sent: Tuesday, October 27, 2015 5:28 PM
To: Pacini, Lain <PaciniLain@stanleygroup.com>
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Lain,

Good afternoon and thank you for reaching out, we appreciate it.

I apologize for the delayed response on your initial request, I was out of the office and missed the note. I have copied a gentlemen named Greg Laemmer on this email as he would probably be a better resource for you on this specific project / request.

Greg,

Will you please review Lain's note below and reach out directly to him with any additional questions you may have in order to provide him with some good feedback?

Thank you again and have a great evening.

Bob

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5380 Cottonwood Lane, Prior Lake, MN 55372
Primary Telephone: 952.836.6601

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bkonkel@miratechcorp.com
www.miratechcorp.com

From: Pacini, Lain [mailto:PaciniLain@stanleygroup.com]
Sent: Tuesday, October 27, 2015 4:28 PM
To: Bob Konkel
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Bob,

I must apologize for misspelling your name in your name in the e-mail below. Do you need any additional information from me in order to be able to answer the control technology questions I have below? Is there a local (Fairbanks, AK) representative within Miratech that may it may be more appropriate to contact?

Thank you for your time and consideration.

Lain Pacini, Q.E.P.
Air Quality Department Manager
Stanley Consultants, Inc.
2658 Crosspark Rd., Suite 100
Coralville, IA 52241
319.626.5306 (phone)
319.626.3993 (fax)
www.stanleyconsultants.com

From: Pacini, Lain
Sent: Friday, October 23, 2015 9:31 AM
To: Bob Konkel <bkonkel@miratechcorp.com>
Cc: 'BMartinson@titanenergy.com' <BMartinson@titanenergy.com>
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Hello Mr. Knokel,

I was referred to you by Mr. Martison as you can see below. I am looking for some information for a client who is asking for options with regard to reducing NOx and PM emissions from a stationary diesel fired emergency engine genset. Information about the engines and the information I am interested in is included below. I am hoping you may be able to help me.

The generator is a diesel fueled Generac 400 kW emergency generator with a serial number of 2083094 and a Mitsubishi engine, model number of 0A8829.

My client is in Alaska (Fairbanks) and has been asked by the state to reduce the above pollutants. You mentioned before that Tier 4 conversion kit for RICE MACT compliance is a possibility. What about a Tier II conversion kit, is that an available option? If so, what would the cost be to have one installed on this type of engine?

You also mentioned that there is an option to add an SCR type catalyst aftermarket alone (not in the conversion box). What is the cost to install a NOx reduction catalyst (not in the conversion kit box)? We are not interested in a CO oxidation catalyst, just the NOx reducing one.

Is there any additional information about the genset you would need to know to answer these questions more accurately?

Thank You,

Lain

From: Brandon Martinson [mailto:BMartinson@titanenergy.com]
Sent: Friday, October 23, 2015 7:58 AM
To: Pacini, Lain <PaciniLain@stanleygroup.com>
Cc: John Hanson <JHanson@titanenergy.com>; Bob Konkel <bkonkel@miratechcorp.com>
Subject: RE: Emissions Control - Generac 400 kW Emergency Genset

Lain,

I am going to refer you to a company called Miratech. They are the experts in this field and may have some solutions and pricing for you. Bob Konkel is cc'd on this e-mail so you have his contact info with Miratech.

Thanks,

Brandon Martinson
Service Manager/MasterTechnician

TITAN ENERGY WORLDWIDE
A Pioneer Critical Power Company
6321 Bury Dr Suite 8
Eden Prairie, MN 55346
Main: 952-960-2371
Email: bmartinson@titanenergy.com

From: Pacini, Lain [mailto:PaciniLain@stanleygroup.com]
Sent: Friday, October 23, 2015 7:49 AM
To: Brandon Martinson
Subject: Emissions Control - Generac 400 kW Emergency Genset

Brandon,

I spoke to you over the phone last week about controlling PM and NOx for the following engine:

The generator is a diesel fueled Generac 400 kW emergency generator with a serial number of 2083094 and a Mitsubishi engine, model number of 0A8829.

My client is in Alaska (Fairbanks) and has been asked by the state to reduce the above pollutants. You mentioned before that Tier 4 conversion kit for RICE MACT compliance is a possibility. What about a Tier II conversion kit, is that an available option? If so, what would the cost be to have one installed on this type of engine?

You also mentioned that there is an option to add an SCR type catalyst aftermarket alone (not in the conversion box). What is the cost to install a NOx reduction catalyst (not in the conversion kit box)? We are not interested in a CO oxidation catalyst, just the NOx reducing one.

Thank You,

Lain Pacini, Q.E.P.
Air Quality Department Manager
Stanley Consultants, Inc.
2658 Crosspark Rd., Suite 100
Coralville, IA 52241
319.626.5306 (phone)
319.626.3993 (fax)
www.stanleyconsultants.com

From: Brandon Martinson [mailto:BMartinson@titanenergy.com]
Sent: Wednesday, October 14, 2015 5:20 PM
To: Wiesbrock, Jimmy
Cc: John Hanson; Rick Jung
Subject: Emissions Control

Jimmy,

I have attached one option for emissions control and we also work with another vendor for another option to add catalyst and aftermarket solutions. Could you give me a call so we can talk on this, I have a few questions to ask you. 651-895-5616

Thanks,

Brandon Martinson
Service Manager/MasterTechnician

TITAN ENERGY WORLDWIDE

A Pioneer Critical Power Company
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Eden Prairie, MN 55346
Main: 952-960-2371
Email: bmartinson@titanenergy.com

TITAN ENERGY WORLDWIDE PIONEER CRITICAL POWER INC.

From: Wiesbrock, Jimmy [mailto:WiesbrockJimmy@stanleygroup.com]
Sent: Tuesday, October 13, 2015 9:26 AM
To: Rick Jung <rjung@titanenergy.com>
Subject: Generator Quetions

Mr. Jung,

The generator is a 400 kW emergency generator with a serial number of 2083094 and an engine number of 0A8829.

The questions I have are as follows:

1) Are there any back end control technologies that can be added to reduce PM emissions? Are diesel particulate filters appropriate for this application?

2) Are there any back end control technologies that can be added to reduce NOx? Are there any similar units that have SCRs installed?

3) Aside from switching ULSD fuel, is there any other way to reduce SOx emissions?

4) Are there modifications to the engine timing that have proven effective in reducing emissions? See the email from Jamie Brewer below for additional information.

5) Are there any engine modifications that would significantly improve engine efficiency (and therefore reduce emissions at rated electrical output)?

6) Is Fuel Injection Timing Retard (FITR) an available control option? What about Ignition Timing Retard (ITR)?

If these are not appropriate control options, the reason(s) would be helpful since both were identified in the RBLC as possible controls for diesel-fired engines over 500 hp. Alternatively, if either option is available, any details and control efficiency estimates would be helpful for preparing the analysis write-up.

Thanks a lot!

Jimmy Wiesbrock

Environmental Scientist

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BACT Analysis Support for EU ID 9A, Medical/Pathological Waste Incinerator

Rubino, Joe

From:	Dean Robbins <dr@thermtec.com>
Sent:	Wednesday, November 04, 2015 2:52 PM
To:	Stevenson, Cindy
Subject:	Re: FW: Questions about a Therm-tec G-30P-1H - FOLLOWUP

Hi Cindy,

Look like you did a good job. By the way, I talked to a couple of Testing Labs and got a estimated cost for testing the 2.5 PM. The additional cost is estimated at $3,000 to $4,000.

Again, this is additional to the standard test method #5 EPA test of about $7,500 to $12,000). If an HCL (etc) test is required, well, we have seen cost of up to $35,000 to $50,000.for Hospital incinerators units based on EPA Medical Waste Incineration requirements.This is a yearly test requirement by EPA.

Thanks for the note - if we can be of help - just call.

Best regards,
Dean

On Wed, Nov 4, 2015 at 12:45 PM, Stevenson, Cindy <StevensonCindy@stanleygroup.com> wrote:

Hello Dean,

Thank you so much for taking the time to talk to me about emission controls for this incinerator. I learned quite a bit from our conversation. As I said, I have to have documentation of some of the costs associated with potential emission controls.

Here are my notes, please review them and let me know if I have understood our discussion correctly.

Regarding installing a fabric filter to control particulate emissions from the incinerator:

Yes, it is possible. However, the flue gas temperature must be reduced prior to entering the baghouse. In order to do this, you must direct the flue gas into a boiler (fire tube boiler), then into a cooling tower, then into the baghouse.

- The boiler will reduce the temperature of the flue gas from approx. 1680 – 1700 F to around 450 F. The cooling tower will further reduce the T from about 450 F to around 300 F.

- The existing exhaust stack will need to be capped so that all of the flue gas is redirected into the boiler. The stack will need to be refractory lined.

- The baghouse operates under negative pressure – and getting a fan to last under these conditions is difficult. If plastics are being incinerated then exhaust gases will contain HCl. The only fans that you've seen that last are Inconel (expensive).

- The baghouse will need to be about 70 bags. It will need to be insulated, and preheated.
- Expect to change bags about every 12-18 months.
- Expect bags to cost about $300 each.
- The baghouse dust could be considered hazardous waste.
- The boiler will need to be cleaned out about once a week, process takes about 2 hours.
- Some installations have to add NaOH to the cooling tower to reduce the pH (low pH due to HCl).

- The approximate capital cost is about $1.2 – 1.4 M.
- The approximate space requirement is about 40' long and 25' wide. (the site doesn't have this space available).
- The reduction in PM2.5 with a baghouse is not accurately known because there is no good test method for PM2.5.

Regarding installing an ESP:

You don't have any experience with this being viable….due to the 10-12% moisture content and high temperature of the flue gas. In general, you have found ESPs to be expensive and inefficient.

Dean – let me know if you agree with these notes, and mark up everything that I didn't get correct. I want to be sure to get it right.

I really appreciate your time and knowledge.

Cindy

Cynthia Stevenson

Environmental Consultant

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stevensoncindy@stanleygroup.com

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From: Stevenson, Cindy
Sent: Tuesday, November 03, 2015 3:37 PM
To: 'artM@WISC.ws' <artM@WISC.ws>
Subject: FW: Questions about a Therm-tec G-30P-1H - FOLLOWUP

Art,

Thanks for taking the time last week to talk to me about this incinerator. I have a little more information on the Therm-tec model G-30P-1H incinerator:

The incinerator is primarily used as a crematory for pathological waste (1 ton/day) and is located on the University of Alaska Fairbanks campus. It is currently operated on Ultra Low Sulfur Diesel fuel. The incinerator consists of four primary incineration burners with two flue duct burners to ensure complete incineration of particles in the flue gases.

The questions that I am asking are:

1. Is it possible to add a fabric filter (baghouse) to control particulate emissions from this incinerator?

2. Is it possible to add an ESP (electrostatic precipitator) to control particulate emissions from this incinerator?

If either or both control technologies are viable, then:

3. For each (baghouse, ESP), what reduction in PM2.5 could reasonably be expected?

4. For each (baghouse, ESP), can you provide a cost estimate to install and operate the emissions control device.

5. For each (baghouse, ESP), can you provide a cost estimate to maintain the emissions control device.

If you are not the correct contact for these questions, can you please point me in the right direction?

Background – portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM2.5, particles with diameters less than 2.5 micrometers in diameter). The Alaska Dept of Environmental Conservation expects that the EPA will change the nonattainment designation for this area from a "moderate" to "serious" next year. This change in designation will require ADEC to submit a plan to the EPA for attainment of the standard. ADEC is in turn asking certain facilities to submit best available control technologies (BACT) for their own sources. For this reason, we are investigating potential control technologies for the above incinerator.

From: Stevenson, Cindy
Sent: Thursday, October 29, 2015 6:54 PM
To: 'artM@WISC.ws' <artM@WISC.ws>
Subject: FW: Questions about a Therm-tec G-30P-1H

From: Stevenson, Cindy
Sent: Tuesday, October 27, 2015 3:21 PM
To: 'artM@WISC.ws' <artM@WISC.ws>
Subject: Questions about a Therm-tec G-30P-1H

Hi Art,

I called Therm-tec last week and they gave me your contact information. We have a client in Fairbanks, AK that has a Therm-Tec incinerator, model G-30P-1H. It was installed in 2006 and has an afterburner (secondary chamber) to control NOx and PM2.5 emissions. Alaska Dept of Environmental Conservation is asking our client to reduce air emissions, so we are starting by asking what options are available. My initial questions are is it possible to install fabric filtration (a baghouse) on this incinerator? Is it feasible to install an electrostatic precipitator (ESP)? I understand that I may not have given you all the information on the incinerator that you need in order to answer my questions – please let me know what you need and I'll get it. Just to give you a heads up: if either (or both) are feasible, my next questions would be about cost.

Thanks very much

Cindy

Cynthia Stevenson

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E-Mail dr@thermtec.com
Web Page www.thermtec.com

From: Courtney Kimball [ckimball@slrconsulting.com]
Sent: December 09, 2015 5:31 PM
To: Julie Ackerlund; Jamie Brewer
Subject: FW: Economic Analyses for UAF
Attachments: FF - BiRD INCINERATOR PM2.5.xlsx

Hi Julie and Jamie,

Here's the first of the cost estimates. I will forward everything I get to both of you, as soon as it comes in. I don't want to bottleneck so I will not review prior to forwarding. Please save everything for your facility in the appropriate file on the server so we have backups.

Courtney Kimball
Senior Engineer
SLR International Corporation

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From: Rubino, Joe [mailto:RubinoJoe@stanleygroup.com]
Sent: December 09, 2015 15:26
To: Courtney Kimball
Cc: Pacini, Lain; Stevenson, Cindy; Solan, John; Rubino, Joe
Subject: Economic Analyses for UAF

Hi Courtney –

I will be sending over the cost analyses we have completed to date for UAF and GVEA over the course of the rest of this week. If Julie or Jamie have specific questions following their review, they can let us know and not have to wait until all the cost sheets have been provided. Starting with BIRD Incinerator at UAF -

1. Fabric filter for PM2.5 emissions control (see attached) – several items to note are as follows:

    a. The source of the capital cost of the equipment and additional maintenance costs is Therm Tec Inc.
    b. The baghouse will need to contain approximately 70 bags. They will need to be insulated and preheated.
    c. The flue gas temperature must be reduced from 1700 degrees F to around 300 degrees F prior to entering the baghouse. In order to do this, you must direct the flue gas into a boiler (fire tube boiler), then into a cooling tower, then into the baghouse.
    d. The existing exhaust stack will need to be capped so that all of the flue gas is redirected into the boiler. The stack will need to be refractory lined.
    e. The baghouse operates under negative pressure – and getting a fan to last under these conditions is difficult. If plastics are being incinerated then exhaust gases will contain HCl.
    f. As far as maintenance costs, expect to change bags about every 12-18 months at a cost of $300.
    g. We used a project life of 15 years since the vendor mentioned the possibility of HCl in the emissions that could contribute to corrosive conditions.
    h. We also assumed a 95% reduction in emissions to be both conservative and realistic.

2. ESP for PM2.5 emissions control – Therm Tec indicated that although they do not have specific applications of using an ESP on an incinerator, they don't feel it is viable due to the 10-12% moisture content and high temperature of the flue gas. In general, they have found ESPs to be expensive and inefficient. I think we should try and use this to argue technical infeasibility so let us know what you think.

More spreadsheets to follow. Thanks.
Joe

This image cannot currently be displayed.

Joe Rubino | Environmental Services Department Manager
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"Creativity can solve almost any problem. The creative act, the defeat of habit by originality, overcomes everything."

BACT Analysis Support for EU IDs 105, 107, 109-111, 114, and 128 through 130, Material Handling Equipment

From: Rubino, Joe [RubinoJoe@stanleygroup.com]
Sent: February 24, 2016 11:49 AM
To: Julie Ackerlund
Cc: Courtney Kimball
Subject: UAF Updates

Hi Julie –

I wanted to let you know that I heard back from Allen-Sherman-Hoff on the filter media for the material handling equipment associated with the new plant. Based on their discussions with the equipment supplier Industrial Accessories Company (IAC), who is familiar with the UAF project, fabric filters consisting of a PTFE (poly-tetra-fluoro-ethylene) membrane will collect filterable $PM_{2.5}$ emissions and meet the project warranty for PM_{10} emissions of 0.003 gr/ dscf (dry particulate only). IAC considers the PM_{10} warranty to also cover filterable $PM_{2.5}$ emissions. Note that the warranty being met is much less than the current PM permit limit of 0.05 gr/cf. IAC also commented that there could be condensable $PM_{2.5}$ in a gaseous state which cannot be collected by a fabric type particulate collector. However, I would not expect to find a significant percentage of condensable PM resulting from these handling processes. I can insert this information into our summary table for project records.

Have you had a chance to think about the approach for considering installation of LNBs on the BiRD incinerator? Since natural gas supply is currently not available and would be required, can an argument be made not to consider this technology? I am still waiting on information from Therm-Tec but wanted to get your thoughts in the interim.

Finally, John Solan was putting in calls today to Phil Meehan at Indeck and the DPF vendor for the DEG engine to see what the latest is on our inquiries. We were expecting information on both fronts this week.

Let me know if you have additional comments or questions. Thanks.

Joe

Stanley Consultants 100 Years

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"Creativity can solve almost any problem. The creative act, the defeat of habit by originality, overcomes everything."

IPM Model – Updates to Cost and Performance for APC Technologies

SCR Cost Development Methodology

Final

January 2017

Project 13527-001

Eastern Research Group, Inc.

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

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This work was funded by the U.S. Environmental Protection Agency (EPA) through Eastern Research Group, Inc. (ERG) as a contractor and reviewed by ERG and EPA personnel.

SCR Cost Development Methodology

Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly impact costs, such as flue gas volume, temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs a facility would incur to install a retrofit control such as project contingency.

Establishment of the Cost Basis

The 2004 to 2006 industry cost estimates for SCR units from the "Analysis of MOG and Ladco's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls" prepared for Midwest Ozone Group (MOG) were used by Sargent & Lundy LLC (S&L) to develop the SCR cost model. In addition, S&L included data from "Current Capital Cost and Cost-effectiveness of Power Plant Emissions Control Technologies" prepared by J. E. Cichanowicz for the Utility Air Regulatory Group (UARG) in 2010, and 2013. The published data were significantly augmented by the S&L in-house database of recent SCR projects. The current industry trend is to retrofit high-dust hot-side SCRs. The cold-side tail-end SCRs encompass a small minority of units and as such were not considered in this evaluation.

The data was converted to 2016 dollars based on the Chemical Engineering Plant Index (CEPI) data. Additional proprietary S&L in-house data from 2012 to 2016 were included to confirm the index validity. Finally, the cost estimation tool was benchmarked against recent SCR projects to confirm the applicability to the current market conditions.

The available data was analyzed in detail regarding project specifics such as coal type, NO_x reduction efficiency, and air pre-heater requirements. The data was refined by fitting each data set with a least-squares curve to obtain an average \$/kW project cost as a function of unit size. The data set was then collectively used to generate an average least-squares curve fit. Based on the recently acquired data, it appears the overall capital

SCR Cost Development Methodology

cost has increased by approximately 15% over the costs published in 2013. Analysis of the data indicates that these units had a high degree of retrofit difficulty, high elevation, or low quality fuel.

The costs for retrofitting a plant smaller than 100 MW increase rapidly due to the economy of size. S&L is not aware of any SCR installations in recent years for smaller than 100-MW units. In light of the recent retirement of smaller than 200-MW size units, the evaluation of SCR technology may not be necessary. The older units, which comprise a large proportion of the plants in this range, generally have more compact sites with very short flue gas ducts running from the boiler house to the chimney. Because of the limited space, the SCR reactor and new duct work can be expensive to design and install. Additionally, the plants might not have enough margins in the fans to overcome the pressure drop due to the duct work configuration and SCR reactor, and therefore new fans may be required.

A combined SCR for small units is not a feasible option. The flue gas from the boiler is treated after the economizer in the SCR before entering the air heater. Thus, SCR is an integral part of the heat recovery cycle of an individual boiler. Each boiler has to be retrofitted with its own SCR reactor. Minor savings can be achieved by utilizing a common reagent storage and preparation system.

The least-squares curve fit was based upon an average of the SCR retrofit projects in recent years. Retrofit difficulties associated with an SCR may result in significant capital cost increases. A typical SCR retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9500 Btu/kWh;
- SO_2 Rate = < 3.0 lb/MMBtu;
- Type of Coal = Bituminous; and
- Project Execution = Multiple lump-sum contracts.

Methodology

Inputs

To predict SCR retrofit costs several input variables are required. The unit size in MW is the major variable for the capital cost estimation followed by the type of fuel (Bituminous, PRB, or Lignite), which will influence the flue gas quantities as a result of the different typical heating values. The fuel type also affects the air pre-heater costs if ammonium bisulfate or sulfuric acid deposition poses a problem. The unit heat rate factors into the amount of flue gas generated and ultimately the size of the SCR reactor and reagent preparation. A retrofit factor that equates to the difficulty of constructing the system must be defined. The NO_x rate and removal efficiency will impact the amount of catalyst required and size of the reagent handling equipment.

SCR Cost Development Methodology

The cost methodology is based on a unit located within 500 feet of sea level. The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base SCR and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure at sea level and that at the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base SCR and balance of plant costs should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base SCR and balance of plant costs

The NO_x removal efficiency specifically affects the SCR catalyst, reagent and steam costs. The lower level of NO_x removal is recommended as:

- 0.07 NO_x lb/MMBtu – Bituminous;
- 0.05 NO_x lb/MMBtu – PRB; and
- 0.05 NO_x lb/MMBtu – Lignite.

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. The base module installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Average retrofit difficulty.

The base modules are:

BMR =	Base SCR cost
BMF =	Base reagent preparation cost
BMA =	Base air pre-heater cost
BMB =	Base balance of plant costs including: ID or booster fans, ductwork reinforcement, piping, etc…
BM =	BMR + BMF + BMA + BMB

SCR Cost Development Methodology

The total base module installed cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10-hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 6% of the CECC and owner's costs. The AFUDC is based on a two-year engineering and construction cycle.

The total project cost is based on a multiple lump-sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the SCR installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs are tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, half of an operator's time is required to monitor a retrofit SCR. The FOMO is based on that half-time requirement for the operations staff.
- The fixed maintenance materials and labor are a direct function of the process capital cost at 0.5% of the BM for units less than 300 MW and 0.3% of the BM for units greater than or equal to 300 MW.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

SCR Cost Development Methodology

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Catalyst replacement and disposal costs;
- Additional power required and unit power cost; and
- Steam required and unit steam cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs are tabulated on a per-megawatt-hour (MWh) basis.
- The reagent consumption rate is a function of unit size, NO_x feed rate, and removal efficiency.
- The catalyst replacement and disposal costs are based on the NO_x removal and total volume of catalyst required.
- The additional power required includes increased fan power to account for the added pressure drop and the power required for the reagent supply system. These requirements are a function of gross unit size and actual gas flow rate.
- The additional power is reported as a percent of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.
- The steam usage is based upon reagent consumption rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Urea cost in $/ton. Due to escalation, urea cost was updated to reflect average 2016 pricing. The urea solution cost includes the cost of a 50% urea solution prepared at the manufacturing site with additives suitable for avoiding corrosion in the injectors and transportation cost. The solution cost is significantly higher than that of solid urea. If solid urea is purchased, it would require additional storage, solutionizing equipment, and additional deionized water processing capability at the plant site.
- Catalyst costs that include removal and disposal of existing catalyst and installation of new catalyst in $/cubic meter. No escalation has been observed for catalyst removal and disposal cost since 2013.
- Auxiliary power cost in $/kWh. No noticeable escalation has been observed for auxiliary power cost since 2013.
- Steam cost in $/1000 lb.
- Operating labor rate (including all benefits) in $/hr.

SCR Cost Development Methodology

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for urea reagent

VOMW = Variable O&M costs for catalyst replacement & disposal

VOMP = Variable O&M costs for additional auxiliary power

VOMM = Variable O&M costs for steam

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 1 shows a complete capital and O&M cost estimate worksheet.

SCR Cost Development Methodology

Table 1. Example of a Complete Cost Estimate for an SCR System

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9500	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.3	<--- User Input
SO2 Rate	E	(lb/MMBtu)	3	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.95	C/10000
Heat Input	I	(Btu/hr)	4.75E+09	A*C*1000
NOx Removal Efficiency	K	(%)	75	<--- User Input
NOx Removal Factor	L		0.9375	K/80
NOx Removed	M	(lb/hr)	1069	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	747	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	845	N*1.13
Aux Power **Include in VOM?** ☑	**P**	**(%)**	**0.55**	0.56*(G*H)^0.43
Urea Cost (50% wt solution)	R	($/ton)	350	<--- User Input
Catalyst Cost	S	($/m3)	8000	<--- User Input (Includes removal and disposal of existing catalyst and installation of new catalyst)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Steam Cost	U	($/klb)	4	<--- User Input
Operating Labor Rate	V	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.			
BMR ($) =	310000*(B)*(L)^0.2*(A*G*H)^0.92	$ 88,780,000	SCR (ductwork modifications and strengthening, reactor, bypass) island cost
BMF ($) =	564000*(M)^0.25	$ 3,225,000	Base reagent preparation cost
BMA ($) =	IF E ≥ 3 AND F=Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$ 8,446,000	Air heater modification / SO3 control (Bituminous only & > 3lb/MMBtu)
BMB ($) =	529000*(B)*(A*G*H)^0.42	$ 7,042,000	ID or booster fans & auxiliary power modification costs
BM ($) =	BMR + BMF + BMA + BMB	$ 107,493,000	Total bare module cost including retrofit factor
BM ($/KW) =		215	Base cost per kW
Total Project Cost			
A1 = 10% of BM		$ 10,749,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 10,749,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 10,749,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$ 139,740,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =		**279**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 6,987,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		$ 146,727,000	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**293**	Total project cost per kW without AFUDC
B2 = 6% of (CECC + B1)		$ 8,804,000	AFUDC (Based on a 2 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$ 155,531,000**	Total project cost
TPC ($/kW) =		**311**	Total project cost per kW

SCR Cost Development Methodology

Table 1 Continued

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9500	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.3	<--- User Input
SO2 Rate	E	(lb/MMBtu)	3	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.95	C/10000
Heat Input	I	(Btu/hr)	4.75E+09	A*C*1000
NOx Removal Efficiency	K	(%)	75	<--- User Input
NOx Removal Factor	L		0.9375	K/80
NOx Removed	M	(lb/hr)	1069	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	747	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	845	N*1.13
Aux Power **Include in VOM?** ☑	**P**	**(%)**	**0.55**	0.56*(G*H)^0.43
Urea Cost (50% wt solution)	R	($/ton)	350	<--- User Input
Catalyst Cost	S	($/m3)	8000	<--- User Input (Includes removal and disposal of existing catalyst and installation of new catalyst)
Aux Power Cost	T	($/kWh)	0.06	<--- User Input
Steam Cost	U	($/klb)	4	<--- User Input
Operating Labor Rate	V	($/hr)	60	<--- User Input (Labor cost including all benefits)

Costs are all based on 2016 dollars

Fixed O&M Cost

FOMO ($/kW yr) = (1/2 operator time assumed)*2080*V/(A*1000)	$	0.13	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = (IF A < 300 then 0.005*BM ELSE 0.003*BM)/(B*A*1000)	$	0.64	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.78**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = N*R/(A*1000)	$	0.52	Variable O&M costs for Urea
VOMW ($/MWh) = (0.4*(G^2.9)*(L^0.71)*S)/(8760)	$	0.35	Variable O&M costs for catalyst: replacement & disposal
VOMP ($/MWh) =P*T*10	$	0.33	Variable O&M costs for additional auxiliary power required including additional fan power
VOMM ($/MWh) = O*U/A/1000	$	0.01	Variable O&M costs for steam
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**1.20**	

Huff, Deanna M (DEC)

From: Huff, Deanna M (DEC)
Sent: Thursday, May 11, 2017 10:05 AM
To: 'Kathleen Hook'; David Fish (dfish@usibelli.com); Dick, Eric; Frances Isgrigg; Isaac Jackson; NMKnight@gvea.com; Stringham, Stephen D CIV USARMY IMCOM PACIFIC (US); Dick, Eric M CIV (US)
Cc: Heil, Cynthia L (DEC); Zach Hedgpeth
Subject: Serious SIP BACT due date

Hello all,
The effective date for the Fairbanks PM 2.5 Non-attainment area going Serious is June 9th, 2017. The BACT analyses are due 60 days after the effective date, which is August 8th, but as soon as possible would be helpful since the Serious SIP is still due December 2017.

Environmental Protection Agency
Rule
Air Quality State Implementation Plans; Approvals and Promulgations:
Determinations of Attainment by the Attainment Date, Determinations of Failure to Attain by the Attainment Date and Reclassification for Certain Nonattainment Areas for the 2006 24-Hour Fine Particulate Matter National Ambient Air Quality Standards
FR Document:
2017-09391
Citation:
82 FR 21711
PDF
Pages 21711-21717 (7 pages)
Permalink

Thanks,
Deanna Huff

-----Original Appointment-----
From: Kathleen Hook [mailto:khook@doyonutilities.com]
Sent: Tuesday, January 24, 2017 11:00 AM
To: Kathleen Hook; Lovell, Ron (DEC sponsored); 'Serena.Lewellyn@fhr.com'; Huff, Deanna M (DEC); Courtney Kimball; DU 1st Floor Conference Room; David Fish (dfish@usibelli.com); Dick, Eric; Frances Isgrigg; Heil, Cynthia L (DEC); Isaac Jackson; NMKnight@gvea.com
Cc: 'Dick, Eric M CIV USARMY USAG (US)'; Shayne Coiley
Subject: Point Sources Meet with ADEC
When: Wednesday, February 01, 2017 10:30 AM-12:00 PM America/Anchorage.
Where: DU 1st Floor Conference Room

ADEC will be in town this week to work with FNSB APCC and Assembly, we thought it would be a good opportunity to get folks together to discuss issues.

Let me know if this time works. Please forward to folks I might have missed.

Meeting Location DU offices, I'll set up a teleconference number for individuals to dial in.

Subject:

-Federal Register notice of re-designation to Serious Area for the Fairbanks nonattainment area

-Serious SIP is at the end of 2017 regardless of re-designation

-What does this mean for point sources and their BACT Analyses?

-BACT timeline in light of re-designation and SIP due date

-Precursor demonstrations purposed by the State will be for NOx, Ammonia, and VOCs for major stationary sources

-BACT should be completed for all pollutants required per source (greater than 70PTE TPY), there is no guarantee that EPA will accept precursor analysis

-How BACT controls are implemented (BACT limits in permits by pollutants, etc.)

THE STATE of ALASKA

GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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Juneau, Alaska 99811-1800
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Toll Free: 866-241-2805
Fax: 907-465-5129
www.dec.alaska.gov

CERTIFIED MAIL: 7017 1450 0002 0295 9684
Return Receipt Requested

October 20, 2017

Frances Isgrigg
Director of Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks by December 22, 2017

Dear Ms. Isgrigg:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the University of Alaska Fairbanks and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the University of Alaska Fairbanks. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Isgrigg on May 11, 2017 notifying her of the reclassification to Serious and included

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

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

Clean Air

a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis was submitted by email to ADEC on February 8, 2017 from University of Alaska Fairbanks. It included emission units found in Operating Permit AQ0316TVP02 Revision 1 and Minor Permit AQ0316MSS06 Revision 2.

ADEC reviewed the BACT analysis provided for the University of Alaska Fairbanks and is requesting additional information to assist it in making a legally and practicably enforceable BACT determination for the source. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public comment along with any precursor demonstrations and BACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for the University of Alaska Fairbanks, it must include the determination in the Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from the University of Alaska Fairbanks. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a
[5] 40. CFR 51.1010(4)

Enclosures:

October 20, 2017	Request for Additional Information for UAF BACT Analysis
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for UAF

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Brittany Crutchfield, ADEC/Air Quality
Frances Isgrigg/University of Alaska Fairbanks
Tim Hamlin, USEPA Region 10
Zach Hedgpeth, USEPA Region 10

ADEC Request for Additional Information
University of Alaska Fairbanks
BACT Technical Memorandum Review
SLR Report July 2016

October 20, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 123 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates". The 10 year equipment life assumption is based on the harsh climate and evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. For references on equipment life see the Texas Region 6 SIP findings[2].

2. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

3. CFB Boiler: SDA and DSI
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[3], US EPA Region 6 found that a reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.
    b. Please provide the documents for the following citations:
        i. "SCI engineering estimates (5 years old) for other SDAs."
        ii. "SCI engineering estimates (5 years old) for other DSI systems"
        iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."

---

[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017

[2] https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0001

[3] 76 FR 81728, December 28, 2011

   iv. "…similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."
   v. "Internet research bulk price" for hydrated lime.
   vi. "Internet research bulk price" for sodium bicarbonate.
   vii. "Current Per kW price based on GVEA data."

4. <u>CFB Boiler: SNCR</u>
   a. Please provide the technical justification for the 10-20% emission reduction stated in the email from Babcok and Wilcox for NOx SNCR.
   b. Please provide documentation for the following citations in the BACT analysis:
      i. Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."
      ii. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
      iii. "Current Per kW price based on GVEA data."
   c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – provide justification for including a 30% contingency factor.

5. <u>CFB Boiler: SCR</u> – Please revise the cost analysis submitted using the EPA updated coast manual chapter pertaining to SCR[4]. Specific comments related to the SCR cost effectiveness analysis include the following:
   a. The recently updated cost manual chapter covering SCR includes information regarding SCR equipment life, and indicates the technology can be expected to last 30 years. Please document why the actual expected equipment life of the control equipment is different from this value.
   b. The BACT analysis as submitted states that the normal exhaust temperature from the CFB boiler is expected to be 1,550-1,650˚F, which is outside of the SCR listed acceptable temperature range. Please provide a technical explanation of why the boiler exhaust temperature is so high. The analysis must also include consideration of high temperature SCR.
   c. Documentation must be provided for the following cited information:
      i. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
      ii. Fab Site Vendor "days based on similar project".
      iii. Onsite Vendor "days based on similar project".
      iv. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."
      v. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
      vi. "Current Per kW price based on GVEA data."
      vii. "Replacement labor based on similar project."
      viii. "Labor cost based on similar project."
   d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – Please include why a 30% contingency factor is accurate.

[4] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

6. EU 3 Mid-Sized Diesel Boiler: PTE – Detailed basis must be provided for the NO_X PTE of 138.8 tpy for EU 3 used in the calculations. If PTE is based on the baseline emission rate used in the FuelTech quote (0.175 lb/MMBtu), the BACT limit proposed for good combustion practices should be 0.175 lb/MMBtu as well.

7. EU 3 Mid-Sized Diesel Boiler: LNB/FGR – This technology is eliminated based on cost effectiveness calculated assuming actual emissions. Please revise the cost analyses to be based on PTE.

8. EU 3 Mid-Sized Diesel Boiler: SCR
   a. Please provide the documentation for following citations in the BACT analysis.
      i. "December 2015 price according to Farmer's Coop Association."
      ii. "Replacement labor based on similar project."
      iii. Transport cost direct to site (SCR catalyst). "Based on similar project."
      iv. Transport cost for spent SCR catalyst. "Based on similar project."
   b. No basis is provided for the SCR freight cost of $20,000.
   c. Initial performance testing cost is included twice.
   d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

9. EU 8 Large Diesel Fired Engine: Operational Scenario – Revise the cost analysis to assume operational hours of the unit up to 40 tpy as the emission limit, currently the calculations assume 8760 hours/yr.

10. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

11. EU 27 ACEP Generator – The BACT analysis includes evaluations of SCR and DPF as applied individually for control of NO_X and $PM_{2.5}$ respectively, from this emission unit. In addition please evaluate combined SCR/DPF.

12. For the purposes of this BACT analysis the cost analysis for each emissions control for each of EUs 4 and 8 should be based on the assumption that the 40 tpy NOx limit will be consumed by the EU being evaluated. Under the current permitting limit it is possible for one of EUs 4 and 8 to be the sole contributor to the 40 tpy of NOx in any given 12 month rolling period. Additionally, the 10 percent capacity limit for EU 4 was removed with the issuance of Minor Permit No. AQ0316MSS04 on August 4, 2016, and is therefore no longer applicable as limited operation for EU 4. Please revise the PTE and cost analysis for these units.

13. Describe for each emission unit type, what constitutes good combustion practices. Include any work or operational practice that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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CERTIFIED MAIL: 7014 0514 0001 9932 8897
Return Receipt Requested

April 24, 2015

Frances Isgrigg
Director of Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Voluntary BACT Analysis for Fairbanks Campus Power Plant

Dear Ms. Isgrigg:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

Background

EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98^{th} percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

• Serious Area SIP inventory development starts:	January, 2015
• BACT kick off meeting:	March 5, 2015
• Submit initial BACT results to ADEC:	December, 2015
• Submit complete/final BACT analysis to ADEC:	March, 2016
• Serious Area SIP modeling by ADEC starts:	March, 2016
• Serious Area designation by EPA (Expected):	June, 2016
• Serious Area SIP draft:	December, 2016
• Serious Area SIP public notice period:	February, 2017
• Serious Area SIP submitted by ADEC to EPA:	December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality

University of Alaska Fairbanks – Serious PM-2.5 NA BACT Analysis
BACT Analysis Review Comments
Report dated January 2017 – SLR

Zach Hedgpeth, PE
EPA Region 10 – Seattle
November 2, 2017

1. <u>Equipment Life</u> – Page 123 of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten year equipment life, nor the underlying assertion regarding wear and tear. The analysis must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers.
2. <u>CFB Boiler: Additional SO_2 Control Technologies</u> – The BACT analysis mentions wet scrubbing technologies, but does not clearly explain the basis for excluding these technologies (such as limestone slurry forced oxidation) from consideration within the analysis. Since wet scrubbing would be expected to represent the highest SO_2 removal efficiency, this technology must be fully evaluated within the BACT analysis. Similarly, the analysis does not evaluate dry flue gas desulfurization or dry scrubbing. This enhanced dry SO_2 control technology can achieve higher removal efficiencies than dry sorbent injection, and must also be evaluated thoroughly within the BACT analysis. The BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.
3. <u>CFB Boiler: SDA and DSI</u>
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[2], EPA Region 6 conducted significant research into the actual expected lifetime of SO_2 control technologies, including wet, semi-dry, and dry scrubbing. Region 6 found that 30 years is a reasonable estimate of actual expected equipment life for these control technologies. The analysis for SDA and DSI therefore should use 30 years unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.
    b. The SDA and DSI cost analyses submitted with this analysis cite the following documents as the basis for costs and other information relied upon in the analysis, however, these documents have not been provided. These documents must be provided in order to rely upon the cited information in the analysis:
        i. "SCI engineering estimates (5 years old) for other SDAs."
        ii. "SCI engineering estimates (5 years old) for other DSI systems"
        iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."
        iv. "…similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."
        v. "Internet research bulk price" for hydrated lime.

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[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017
[2] 76 FR 81728, December 28, 2011

   vi. "Internet research bulk price" for sodium bicarbonate.
   vii. "Current Per kW price based on GVEA data."

4. CFB Boiler: SNCR
   a. Within an email included in Appendix B, Babcock & Wilcox states only minimal NO_X reduction of around 10-20% would be expected from SNCR. In order to base the cost analysis on this minimal emission reduction, detailed technical justification must be submitted providing a rigorous basis for why SNCR can only achieve this smaller than average/expected emission reduction for this emission unit.
   b. The SNCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
      i. Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."
      ii. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
      iii. "Current Per kW price based on GVEA data."
   c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

5. CFB Boiler: SCR – The EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness[3]. The cost analysis submitted as part of this BACT analysis[4] does not use the EPA cost spreadsheet. Specific comments related to the SCR cost effectiveness analysis include the following:
   a. The recently updated cost manual chapter covering SCR includes information regarding SCR equipment life, and indicates the technology can be expected to last 30 years. The analysis should use 30 years as the equipment life for SCR unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.
   b. The BACT analysis as submitted states that the normal exhaust temperature from the CFB boiler is expected to be 1,550-1,650˚F. This factor is listed as a technical feasibility issue for SCR as a potential control technology since the temperature range for SCR is listed as 500-800˚F. Please provide a technical explanation of why the boiler exhaust temperature is so high, and why additional heat recovery has not been included in the design of the new power plant. The analysis must also include thorough analysis of high temperature SCR with respect to technical feasibility and cost effectiveness.
   c. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
      i. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
      ii. Fab Site Vendor "days based on similar project".
      iii. Onsite Vendor "days based on similar project".

[3] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution
[4] "UAF BACT NOx Tables 3-X.xlsx"

    iv. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."
    v. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."
    vi. "Current Per kW price based on GVEA data."
    vii. "Replacement labor based on similar project."
    viii. "Labor cost based on similar project."
  d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

6. <u>EU 3 Mid-Sized Diesel Boiler: PTE</u> – Detailed basis must be provided for the NO_X PTE of 138.8 tpy for EU 3 used in the calculations. Note that page 19 of the Title V statement of basis[5] states that emissions from this boiler "in terms of ton/yr were never and will not be limited". Based on the proposed BACT limit of 0.2 lb/MMBtu for good combustion practices, it appears the PTE should, at a minimum, reflect full load operation at this emission rate for 8,760 hours/year (about 158 tpy). If PTE is based on the baseline emission rate used in the FuelTech quote (0.175 lb/MMBtu), the BACT limit proposed for good combustion practices should be 0.175 lb/MMBtu as well.
7. <u>EU 3 Mid-Sized Diesel Boiler: LNB/FGR</u>
  a. This technology is eliminated based on cost effectiveness calculated assuming actual emissions. All cost analyses and BACT determinations must be based on PTE.
  b. On page 39, the BACT analysis describes this control option as "installation of a new burner on the boiler that is already equipped with a LNB and FGR". The analysis must clarify the current status of the boiler with respect to LNB and FGR technology. If the boiler is already equipped with FGR, detailed technical justification must be provided regarding why the fan(s) and/or ducting must be replaced.
8. <u>EU 3 Mid-Sized Diesel Boiler: SCR</u>
  a. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
    i. "December 2015 price according to Farmer's Coop Association."
    ii. "Replacement labor based on similar project."
    iii. Transport cost direct to site (SCR catalyst). "Based on similar project."
    iv. Transport cost for spent SCR catalyst. "Based on similar project."
  b. No basis is provided for the SCR freight cost of $20,000.
  c. Initial performance testing cost is included twice.
  d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.
9. <u>EU 3 Mid-Sized Diesel Boiler: ULSD</u> – The ULSD cost analysis is based on "review of UAF's fuel costs from FY 2011 through 2016. Average of the FY 2014 through 2016 is used, which is 28 cents per gallon more to use ULSD." The documents forming the basis for this information must be submitted in order to rely on this information for purposes of the analysis.
10. <u>EU 8 Large Diesel Fired Engine: Operational Scenario</u> – The NO_X BACT analysis for this unit applies the facility-requested 40 ton per year emission limit, and bases the analysis on an

[5] ADEC Permit No. AQ0316TVP02, Significant Revision 1: June 22, 2012, Statement of Basis

assumed NO_X reduction of only 36 tons (90% reduction from 40 tpy). However, the analysis assumes that the unit operates 8,760 hours/year when calculating the annual O&M costs (i.e., see aqueous ammonia cost). The assumptions underlying the cost analysis are therefore inconsistent. The cost effectiveness analysis must be revised to be consistent based on the assumed operational scenario for the unit. For example, if the unit is assumed to operate uncontrolled for NO_X up to the 40 ton/year limit, the corresponding costs associated with only those limited number of hours may be included. This applies to all annual operating & maintenance costs, including catalyst life.

11. EU 8 Large Diesel Fired Engine: SCR – Please provide detailed information regarding the visible emissions described in the BACT analysis which were observed during operation of the SCR currently installed on the large diesel engine. See page 19.
12. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, but provides no technical analysis or other quantitative or analytical basis for this argument. Further, the BACT analysis determines that an appropriate DPF "likely does not exist" without citing any information from established DPF equipment suppliers. The BACT analysis cites only a single local Fairbanks engine company, whose employee states that the company has "never supplied a DPF with a new engine or for after market use". The information provided forms insufficient basis to reject DPF as technically infeasible and/or not cost effective. The analysis must provide detailed technical analysis of the back pressure issue by an engineering firm or control equipment supplier with the necessary expertise regarding the control technology. In order to establish the availability of a suitable DPF, the analysis must include information regarding these topics from established DPF control equipment suppliers. The availability of this control technology is not limited to DPF equipment currently available "off the shelf". UAF must explore whether manufacture of an appropriate DPF for this emission unit is technically feasible, and conduct an emission unit specific cost analysis following the EPA Cost Manual.
13. EU 27 ACEP Generator – The BACT analysis includes evaluations of SCR and DPF as applied individually for control of NO_X and $PM_{2.5}$ respectively, from this emission unit, however a combination SCR/DPF was not evaluated. The analysis must be revised to include a cost effectiveness analysis for this combined control technology.

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December 21, 2017

Denise Koch, Director
Alaska Department of Environmental Conservation
Division of Air Quality
410 Willoughby Avenue, Suite 303
Juneau, Alaska 99811-1800

Subject: ADEC Request for additional information for the Best Available Control Technology for University of Alaska Fairbanks

Dear Ms. Koch:

The University of Alaska Fairbanks (UAF) received a request for additional information regarding the Best Available Control Technology (BACT) analysis from the Alaska Department of Environmental Conservation (ADEC) on October 20, 2017. This request included a set of 13 comments. ADEC provided a second set of comments and information requests from the US Environmental Protection Agency (EPA) Region 10 on November 6, 2017.

UAF understands that ADEC expects responses to both sets of comments. EPA Region 10 comments 1 through 8 are similar or identical to ADEC comments 1 through 8. EPA Region 10 comments 9 and 11 address issues that were not mentioned in the ADEC comments. Comment 10 from EPA Region 10 is a similar question to comment 9 from ADEC, and comments 12 and 13 from EPA Region 10 are comparable to ADEC comments 10 and 11. Comments 12 and 13 from ADEC were not addressed in the EPA Region 10 comments.

UAF is providing responses to each comment from EPA Region 10, and to ADEC comments 12 and 13, thus addressing each comment from both agencies. Each comment is repeated verbatim in the attachment, followed by the UAF response.

If you have any questions or require additional information regarding this response, please feel free to contact me using the information below my signature.

Sincerely,

Russ Steiger
Environmental Compliance Officer
University of Alaska Fairbanks
Office of Environmental, Health, Safety, and Risk Management
Office: (907) 474-5812
Mobile: (716) 534-1511
Email: rhsteiger@alaska.edu

Enclosures:

Attachment 1: UAF Response to EPA Region 10 and ADEC Comments on BACT Analysis

cc (email) Deanna Huff/ADEC
Cindy Heil/ADEC
Aaron Simpson/ADEC
Denise Koch/ADEC
Zach Hedgpeth/EPA Region 10
Frances Isgrigg/UAF EHSRM

ATTACHMENT 1
UAF RESPONSE TO EPA REGION 10 and ADEC COMMENTS ON BACT ANALYSIS

EPA Region 10 Comments

1. Equipment Life – Page 123 of the analysis states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten-year equipment life, nor the underlying assertion regarding wear and tear. The analysis must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers.

UAF Response to Comment 1:
Consistent with established ADEC practice and previously approved PSD permitting BACT analyses, a 10-year equipment life was used in the calculation of the capital recovery factor for the UAF BACT analysis. This 10-year equipment life timeframe is appropriate for equipment operated in the harsh Alaska climate. Two recent permits with BACT analyses based on a 10-year life are Permit No. AQ0237CPT04 (see footnote to Table B-4 of the Technical Analysis Report) and Permit No. AQ0083CPT06 (see page 24 of Technical Analysis Report).

The EPA Air Pollution Control Cost Manual (sixth edition, EPA/452/B-02-001, Control Cost Manual) uses equipment lifetimes between 5 and 30 years. Ten, 15, and 20-year lifespans are frequently used in the manual.

The updated selective catalytic reduction (SCR) section of the Control Cost Manual states "broadly speaking, a representative value of the equipment life for SCR at power plants can be considered as 30 years. For other sources, the equipment life can be between 20 and 30 years. The remaining life of the boiler may also be a determining factor for the system lifetime." The updated selective non-catalytic reduction (SNCR) section of the Control Cost Manual uses a 20-year lifespan in the example analysis, based on three petroleum refiners who estimated SNCR life at between 15 and 25 years.

Draft comment 1 from ADEC cited a proposed federal rulemaking addressing a regional haze determination from EPA Region 6. The preamble to the proposed rule includes a discussion of equipment life for sulfur dioxide (SO_2) scrubbers. The preamble states that a prior Oklahoma Federal Implementation Plan (FIP) used a lifetime of 30 years to determine costs for SO_2 scrubbers. Expanding the use of the Oklahoma FIP 30-year equipment life to the UAF equipment is not appropriate because the technically feasible emission controls identified for the UAF emission units (with the exception of EU 113) do not include SO_2 scrubbers. Additionally, *emission control equipment that may be suitable for use in Oklahoma may not be suitable for use in Interior Alaska, for obvious reasons.*

A 30-year equipment life for control equipment on EU 113 is inconsistent with EPA long-standing guidance regarding equipment life determinations. The 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting states on page b.10 of Appendix B that "The economic life of a control system typically varies between 10 to 20 years and longer ***and*** *should be determined consistent with data from EPA cost support documents and the IRS Class Life Asset Depreciation Range System" (emphasis added). EU 113 will be a co-generation boiler that will produce steam for campus heat, as well as steam for the generation of electricity. Table B-1 of IRS Publication 946 (2016) provides a class life, or a tax cost recovery period, of 22 years for assets associated with Industrial Steam and Electric Generation and/or Distribution Systems (see Asset Class 00.4). As a result, a 30-year equipment life is not consistent with the EPA policy that the economic life of a control system should also be consistent with the IRS Class Life Asset Depreciation Range System.*

2. <u>CFB Boiler: Additional SO_2 Control Technologies</u> – The BACT analysis mentions wet scrubbing technologies, but does not clearly explain the basis for excluding these technologies (such as limestone slurry forced oxidation) from consideration within the analysis. Since wet scrubbing would be expected to represent the highest SO_2 removal efficiency, this technology must be fully evaluated within the BACT analysis. Similarly, the analysis does not evaluate dry flue gas desulfurization or dry scrubbing. This enhanced dry SO_2 control technology can achieve higher removal efficiencies than dry sorbent injection, and must also be evaluated thoroughly within the BACT analysis. The BACT analysis must include rigorous site-specific evaluation of the technical feasibility and cost effectiveness of these technologies.

<u>UAF Response to Comment 2:</u>
The circulating fluidized bed (CFB) boiler design includes integrated dry scrubbing control technology. The CFB boiler incorporates dry scrubbing technology by way of the limestone injection system that is inherent to the CFB design. Wet scrubbing is typically not used in conjunction with CFB technology. The RACT/BACT/LAER Clearinghouse (RBLC) database does not list any applications of wet scrubbers used with CFB boilers. Wet scrubbing is essentially a more expensive version of dry scrubbing, and therefore is only utilized for the biggest, most challenging scrubbing applications. Because dry scrubbing technology has advanced to achieving approximately the same control efficiency as wet scrubbing (90 percent or greater), the cost effectiveness for wet scrubbing would only be higher due to the higher capital cost.

Please refer to the email from David Novogoratz at Babcock and Wilcox (B&W) to John Solan on February 1, 2016 in Appendix B of the BACT analysis report. B&W indicates that dry sorbent injection (DSI) and semi-dry scrubbing are feasible post-combustion SO_2 controls for the boiler. The DSI control system evaluated in the BACT analysis is in addition to the dry scrubbing that occurs within the boiler bed.

3. CFB Boiler: SDA and DSI
   a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze, EPA Region 6 conducted significant research into the actual expected lifetime of SO_2 control technologies, including wet, semi-dry, and dry scrubbing. Region 6 found that 30 years is a reasonable estimate of actual expected equipment life for these control technologies. The analysis for SDA and DSI therefore should use 30 years unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.

      UAF response to Comment 3a:
      The Control Cost Manual does not indicate the use of a 30-year equipment life for any SO_2 emission control systems. The Control Cost Manual, Section 5.2, Chapter 1, paragraph 1.5.2, provides a 15-year equipment life for a wet scrubber, and cites Section 1 of the manual regarding capital recovery costs.

      The EPA Region 6 use of a 30-year life for SO_2 scrubbers is not necessarily consistent with the EPA Cost Control Manual or Appendix B of the 1990 New Source Review Workshop Manual, and is not a mandate for all future BACT analyses to use 30-year lifespans for SO_2 emission control systems.

      UAF does not agree that a 30-year equipment life is appropriate, as discussed in the response to Comment 1 above. As a courtesy, UAF did re-calculate the cost analysis with a basis of a 15-year equipment life. For a spray dryer absorber (SDA), the cost effectiveness would be $11,598 per ton of SO_2 avoided and for dry sorbent injection (DSI), the cost effectiveness would be $8,186 per ton of SO_2 avoided.

   b. The SDA and DSI cost analyses submitted with this analysis cite the following documents as the basis for costs and other information relied upon in the analysis, however, these documents have not been provided. These documents must be provided in order to rely upon the cited information in the analysis:
      i. "SCI engineering estimates (5 years old) for other SDAs."

         UAF response to Comment 3b(i):
         These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency.

      ii. "SCI engineering estimates (5 years old) for other DSI systems"

         UAF response to Comment 3b(ii):
         These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency.

iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."

UAF response to Comment 3b(iii):
These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency.

iv. "...similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

UAF response to Comment 3b(iv):
These estimates were based on a Boiler MACT compliance feasibility study prepared by SCI for a confidential client. This documentation is client confidential and cannot be provided to the agency. The FTEK SCR quote was provided in Appendix B of the BACT analysis report.

v. "Internet research bulk price" for hydrated lime.

UAF response to Comment 3b(v):
The cost of $560/ton for hydrated lime was conservatively high. Based on more recent internet research, the price for bulk hydrated lime is estimated to be approximately $150/ton (lime plant value) per this website: https://minerals.usgs.gov/minerals/pubs/commodity/lime/mcs-2017-lime.pdf. Delivery to Fairbanks, Alaska would incur a higher, unknown cost. Using $150/ton in the analysis is therefore conservatively low. This adjustment results in minimal reduction to the cost effectiveness value for the use of SDA control.

vi. "Internet research bulk price" for sodium bicarbonate.

UAF Response to Comment 3b(vi):
Sodium bicarbonate price rates are available at http://www.sodaashdirect.com/buy-sodium-carbonate-online.html. The prices provided on this website do not include shipping costs. The cost of $700/ton presented in the analysis is likely conservatively low when accounting for delivery to Fairbanks, Alaska.

vii. "Current Per kW price based on GVEA data."

UAF Response to Comment 3b(vii):
The electrical utility provider in Fairbanks, Golden Valley Electric Association (GVEA) currently charges $0.209 per kilowatt-hour. The UAF BACT analysis cites $0.18 per kilowatt-hour because that particular calculation was prepared in 2016. Current GVEA rates are available at http://www.gvea.com/rates/rates.

4. CFB Boiler: SNCR

a. Within an email included in Appendix B, Babcock & Wilcox states only minimal NO_X reduction of around 10-20% would be expected from SNCR. In order to base the cost analysis on this minimal emission reduction, detailed technical justification must be submitted providing a rigorous basis for why SNCR can only achieve this smaller than average/expected emission reduction for this emission unit.

UAF Response to Comment 4a:
Babcock and Wilcox (B&W) is the boiler manufacturer for EU 113, and is the source of technical expertise about this boiler. The SNCR emission reduction efficiencies discussed in the Control Cost Manual can be quite low, particularly for coal-fired boilers with low nitrogen oxides (NO_X) concentrations at the inlet to the emission control system. (See Figures 1.1a and 1.1c in Chapter 1, Section 1 in the updated SNCR chapter of the Control Cost Manual.) B&W has significant experience providing NO_X control systems for utility boilers such as EU 113. Given the B&W involvement in the design of the UAF CFB boiler, depth of knowledge of boiler exhaust characteristics and extensive knowledge on reductions that can be achieved from an SNCR control system, B&W has the expertise to make this determination. UAF accepts the B&W expert analysis of control technology for the CFB boiler and so is not providing additional justification for the SNCR NO_X emission reduction efficiencies.

b. The SNCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:

i. Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."

UAF Response to Comment 4b(i):
The indirect capital costs are calculated using 18 percent of the total direct cost (purchased equipment and material costs and direct installation costs). The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used the same ratio. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 18 percent is an appropriate ratio for the EU 113 SNCR cost analysis.

ii. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."

UAF Response to Comment 4b(ii):
Several different references indicate that ammonia solution has a specific gravity of approximately 0.9. The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used an ammonia

solution cost of $0.75 per gallon. Please see Page 23 of the TAR to Permit No. AQ1201CPT01. Consistent with that ADEC-approved analysis, UAF believes that a cost of $0.75 per gallon is representative of ammonia costs for this analysis.

UAF notes that if any aqueous ammonia were to be used, the concentration of that solution would be less than 20 percent. The freezing point of 19 percent aqueous ammonia is -30 degrees Fahrenheit. Ambient temperatures during winter in Interior Alaska routinely drop below -30 degrees Fahrenheit, so considerations for heat tracing, circulation, as well as shipment of the solution to Fairbanks (with the inherent risk in supply disruption) are all likely to result in higher costs.

iii. "Current Per kW price based on GVEA data."

UAF Response to Comment 4b(iii):
The electrical utility provider in Fairbanks, Golden Valley Electric Association (GVEA) currently charges $0.209 per kilowatt-hour. The UAF BACT analysis cites $0.18 per kilowatt-hour because that particular calculation was prepared in 2016. Current GVEA rates are available at http://www.gvea.com/rates/rates.

c. The budgetary nature of the costs provided by Fuel Tech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

UAF Response to Comment 4c:
The capital costs for an SNCR system on the CFB boiler were provided by Babcock & Wilcox (B&W). The B&W estimate did not include any contingency costs. Because preparing a BACT analysis requires obtaining vendor pricing information without knowing the exact final emission limits, the vendor could not be provided with a precise emissions target. The vendor therefore must rely upon their general experience of what percent reduction could be achieved by an SNCR system. Applying a contingency factor in the cost effectiveness evaluation is both practical and appropriate. Use of a contingency factor for costs associated with control device retrofits is also consistent with a Boiler MACT compliance feasibility study prepared by SCI for a confidential client with six coal-fired boilers. Please see also the UAF response to Comment 4b(ii) above.

A contingency cost of 30 percent was applied to equipment and material costs, direct installation costs, and engineering and procurement costs in the BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 30 percent is an appropriate ratio for the EU 113 SNCR cost analysis.

5. CFB Boiler: SCR – The EPA has recently updated the cost manual chapter pertaining to SCR,

and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The cost analysis submitted as part of this BACT analysis does not use the EPA cost spreadsheet. Specific comments related to the SCR cost effectiveness analysis include the following:

a. The recently updated cost manual chapter covering SCR includes information regarding SCR equipment life, and indicates the technology can be expected to last 30 years. The analysis should use 30 years as the equipment life for SCR unless documented evidence is provided establishing that the actual expected equipment life of the control equipment is different from this value.

   UAF Response to Comment 5a:
   The updated SCR section of the Control Cost Manual states "broadly speaking, a representative value of the equipment life for SCR at power plants can be considered as 30 years. For other sources, the equipment life can be between 20 and 30 years. The remaining life of the boiler may also be a determining factor for the system lifetime."

   UAF does not agree that a 30-year equipment life is appropriate, as discussed in the response to Comment 1 above. As a courtesy, UAF did re-calculate the cost analysis with a basis of a 20-year equipment life. For selective catalytic reduction (SCR), the cost effectiveness would be $22,232 per ton of NO_X emissions avoided.

b. The BACT analysis as submitted states that the normal exhaust temperature from the CFB boiler is expected to be 1,550-1,650°F. This factor is listed as a technical feasibility issue for SCR as a potential control technology since the temperature range for SCR is listed as 500-800°F. Please provide a technical explanation of why the boiler exhaust temperature is so high, and why additional heat recovery has not been included in the design of the new power plant. The analysis must also include thorough analysis of high temperature SCR with respect to technical feasibility and cost effectiveness.

   UAF Response to Comment 5b:
   The BACT analysis report correctly states on page 11 that the boiler combustion temperature is expected to range between 1,550 and 1,650 °F. UAF acknowledges that the description of the exhaust gas temperature provided on page 12 of the BACT analysis is not accurate.

   Stanley Consultants contacted Babcock and Wilcox (B&W) to seek clarification of exhaust gas characteristics. B&W indicated that the predicted flue gas temperatures at maximum combustion rate (MCR) conditions for the CFB boiler as listed on the performance summary sheet for the boiler are as follows:

   - *Exit of generating bank* *774°F*
   - *Inlet of economizer* *774°F*
   - *Exit of economizer* *463°F*
   - *Exit of air preheater* *335°F*

The ideal gas temperature for NO_X reduction ranges for SCR is from 700 to 750°F. (Steam – Its Generation and Use, Babcock & Wilcox, 42nd Edition, 2015). In utility boilers, the typical SCR system would be placed at the economizer outlet, preceding the air heater. As shown in the above temperature profile, the exit temperature at the economizer outlet is well below the ideal range. The exhaust flow coming out of the boiler is closer to this documented range, however design modifications would be needed to fit the SCR system into this arrangement and would involve a redesign of structure of the baghouse building to accommodate the installation of the SCR above the baghouse. Given the seismic design criteria of the site, this would be a challenging and expensive undertaking. These unique characteristics only serve to drive up capital costs and consequently the cost effectiveness value of the SCR control system.

c. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:

i. "Cost of startup spares indicated as a percentage of equipment cost per similar project."

UAF Response to Comment 5c(i):
The cost of startup spares was estimated as a percentage of equipment cost in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the cost for startup spare equipment estimated at 0.50 percent of total equipment costs is reasonable for purposes of this analysis.

ii. Fab Site Vendor "days based on similar project".

UAF Response to Comment 5c(ii):
The fabrication site vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that these vendor fees are reasonable for purposes of this analysis.

iii. Onsite Vendor "days based on similar project".

UAF Response to Comment 5c(iii):
The onsite vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that these vendor fees are reasonable for purposes of this analysis.

iv. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."

UAF Response to Comment 5c(iv):
The indirect capital costs are calculated using 18 percent of the total direct cost (purchased equipment and material costs and direct installation costs). The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used the same ratio. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 18 percent is an appropriate ratio for the EU 113 SNCR cost analysis.

v. "ammonia solution cost from similar BACT analysis - $0.75/gal and specific gravity of 0.9."

UAF Response to Comment 5c(v):
Several different references indicate that ammonia solution has a specific gravity of approximately 0.9. The BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility used an ammonia solution cost of $0.75 per gallon. Please see Page 23 of the TAR to Permit No. AQ1201CPT01. Consistent with that ADEC-approved analysis, UAF believes that a cost of $0.75 per gallon is representative of ammonia costs for this analysis.

UAF notes that if any aqueous ammonia were to be used, the concentration of that solution would be less than 20 percent. The freezing point of 19 percent aqueous ammonia is -30 degrees Fahrenheit. Ambient temperatures during winter in Interior Alaska routinely drop below -30 degrees Fahrenheit, so considerations for heat tracing, circulation, as well as shipment of the solution to Fairbanks (with the inherent risk in supply disruption) are all likely to result in higher costs.

vi. "Current Per kW price based on GVEA data."

UAF Response to Comment 5c(vi):
The electrical utility provider in Fairbanks, Golden Valley Electric Association (GVEA) currently charges $0.209 per kilowatt-hour. The UAF BACT analysis cites $0.18 per kilowatt-hour because that particular calculation was prepared in 2016. Current GVEA rates are available at http://www.gvea.com/rates/rates.

vii. "Replacement labor based on similar project."

UAF Response to Comment 5c(vii):
The catalyst replacement manhours were assumed to be comparable to those manhours determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the labor hour estimate is appropriate for purposes of this analysis.

viii. "Labor cost based on similar project."

UAF Response to Comment 5c(viii):
The catalyst replacement labor rate was assumed to be comparable to the catalyst replacement labor rate determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. The labor rate is likely conservatively low because the cost is not reflective of 2017 labor rates. UAF believes the rate is representative of labor costs for purposes of this analysis.

d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

UAF Response to Comment 5d:
The capital costs for an SCR system on the CFB Boiler were provided by Babcock & Wilcox (B&W). The estimate did not include any contingency costs. B&W did indicate that minimal space for an SCR retrofit is available. The arrangement to add SCR would be very complicated arrangement. This issue was not otherwise factored into the budgetary estimates provided. Because preparing a BACT analysis requires obtaining vendor pricing information without knowing the exact final emission limits, the vendor could not be provided with a precise emissions target. The vendor therefore must rely upon their general experience of what percent reduction could be achieved by an SCR system. Applying a contingency factor in the cost effectiveness evaluation seems both practical and appropriate. Use of a contingency factor for costs associated with control device retrofits is also consistent with a Boiler MACT compliance feasibility study prepared by SCI for a confidential client with six coal-fired boilers. Please see also the UAF response to Comment 5c(v) above.

A contingency cost of 30 percent was applied to equipment and material costs, direct installation costs, and engineering and procurement costs in the BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 30 percent is an appropriate ratio for the EU 113 SNCR cost analysis.

UAF notes that removing the contingency factor from the cost analysis calculation results in a cost effectiveness of $28,425/ton of NO_X removed (as opposed to $23,915/ton when including the 30 percent contingency). Disuse of the contingency factor does not alter the result that SCR cannot be determined to be BACT for EU 113.

6. <u>EU 3 Mid-Sized Diesel Boiler: PTE</u> – Detailed basis must be provided for the NO_X PTE of 138.8

tpy for EU 3 used in the calculations. Note that page 19 of the Title V statement of basis states that emissions from this boiler "in terms of ton/yr were never and will not be limited". Based on the proposed BACT limit of 0.2 lb/MMBtu for good combustion practices, it appears the PTE should, at a minimum, reflect full load operation at this emission rate for 8,760 hours/year (about 158 tpy). If PTE is based on the baseline emission rate used in the FuelTech quote (0.175 lb/MMBtu), the BACT limit proposed for good combustion practices should be 0.175 lb/MMBtu as well.

UAF Response to Comment 6:
The baseline NO_X emission rate of 0.175 lb/MMBtu is an emission rate which Fuel Tech used to prepare a cost estimate for an SCR system. Assuming an existing NO_X emission rate for EU 3 was necessary to prepare a cost estimate for a NO_X emission control system. (The vendor could also not be provided with a precise emissions target, because the nature of a BACT analysis requires obtaining vendor pricing without knowing the exact final emission limit.) The baseline NO_X emission rate of 0.175 lb/MMBtu is not a vendor-guaranteed emission rate. Fuel Tech is the SCR controls system vendor but is not the vendor that manufactured EU 3.

EU 3 was installed in 1970 and is almost 50 years old. NO_X emission rates depend on combustion efficiency, the amount of fuel-bound nitrogen, and several other factors. The exact NO_X emission profile of EU 3 is not known. (Please refer to the letter from Indeck dated February 5, 2016, provided in Appendix B of the UAF BACT analysis.) UAF does not wish to commit to a BACT limit which is less than 0.2 lb/MMBtu due to these unknowns. (The 40 CFR 60 Subpart Db NSPS NO_X emission limit is also 0.2 lb/MMBtu. The AP-42 emission factor of 24 lb/1,000 gallons of diesel (Table 1.3-1) is dependent on fuel heat content. Assuming a diesel heating value of 0.137 MMBtu/gallon, the resulting emission rate is 0.175 lb/MMBtu, which is less than the NSPS limit.) UAF believes that 0.2 lb/MMBtu is an appropriate and reasonable BACT limit for EU 3, given the age of the boiler and the unknown variables involved.

7. EU 3 Mid-Sized Diesel Boiler: LNB/FGR
    a. This technology is eliminated based on cost effectiveness calculated assuming actual emissions. All cost analyses and BACT determinations must be based on PTE.

    UAF Response to Comment 7a:
    The cost analysis for LNB/FGR emission controls on EU 3 based on potential to emit (PTE) is presented in the BACT report that UAF submitted to ADEC. The cost effectiveness of LNB/FGR for EU 3 is \$3,634 per ton of NO_X removed, as shown in Table 3-18 and discussed on page 40 of the report.

    EU 3 is oil-fired and is operated as a backup boiler. Recent actual NO_X emissions are less than five percent of PTE for EU 3. The new CFB boiler, EU 113, which is currently being installed, will be more reliable than the existing coal-fired boilers which have been the primary source of steam at the UAF Central Heat and Power Plant (CHPP). EU 3 will continue in this backup role and so is not expected to be operated often. The actual emissions reductions achieved through installing LNB/FGR would be *minimal (i.e., less than 4 tons per year of NO_X removed). The effective cost of installing the controls would be approximately $35,500 per ton of NO_X removed, as discussed on page 41 of the report.*

UAF understands that BACT cost analyses are typically based on PTE as opposed to actual emissions. UAF also understands that BACT decisions are based on case-by-case analysis. As a result, an exception to this typical approach is appropriate in this case because:

- *EU 3 has a long history of infrequent use as backup boiler;*
- *The installation of EU 113 is expected to further reduce the operating frequency of EU 3; and*
- *The cost effectiveness of installing LNB/FGR equipment on EU 3 is very high based on the expected infrequent operation of this boiler.*

As a practical matter, the analysis demonstrates that installing LNB/FGR equipment on EU 3 is not a cost effective method to reduce NO_X emissions from EU 3.

b. On page 39, the BACT analysis describes this control option as "installation of a new burner on the boiler that is already equipped with a LNB and FGR". The analysis must clarify the current status of the boiler with respect to LNB and FGR technology. If the boiler is already equipped with FGR, detailed technical justification must be provided regarding why the fan(s) and/or ducting must be replaced.

<u>UAF Response to Comment 7b:</u>
UAF acknowledges that the description provided on page 39 of the BACT analysis is not accurate. EU 3 is not equipped with LNB or FGR technology. The letter from Indeck dated February 5, 2016, provided in Appendix B of the report, states the following. "The low NO_X burners offered here may be operated with the existing boiler force draft (FD) fans with some possible shortness of full MCR steam rating due to the settings of the existing equipment. If lower NOx levels are desired, these FD fans must be replaced with new FD fans and motors designed to allow for induced flue gas recirculation (FGR) from the boiler flue gas outlet. Optional pricing for these FD fans with FGR capability is provided."

In the letter, Indeck provided information about the existing burners, new LNB without FGR, and new LNB with FGR. The letter states that installing FGR would require the replacement of the existing forced draft (FD) fan and motor.

8. <u>EU 3 Mid-Sized Diesel Boiler: SCR</u>
   a. The SCR cost analysis cites the following documents and information as the basis for costs and other information relied upon in the analysis, however, documentation for these values and information has not been provided. Documentation must be provided in order to rely upon the cited information in the analysis:
      i. "December 2015 price according to Farmer's Coop Association."

UAF Response to Comment 8a(i):
The Farmer's Coop Association price web page is available at http://www.farmersco-op.coop/pages/custom.php?id=21023. Although prices change slightly over time, UAF believes the $356 cost per ton of urea is representative for this analysis.

ii. "Replacement labor based on similar project."

UAF Response to Comment 8a(ii):
The catalyst replacement manhours and labor rate were assumed to be comparable to the manhours determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the labor hour cost estimate for catalyst replacement is appropriate for purposes of this analysis.

iii. Transport cost direct to site (SCR catalyst). "Based on similar project."

UAF Response to Comment 8a(iii):
The catalyst transportation cost was assumed to be comparable to transport costs determined in a similar project. The UAF consultant indicates that the project was prepared for a confidential client. UAF believes that the catalyst transport cost estimate is appropriate for purposes of this analysis.

iv. Transport cost for spent SCR catalyst. "Based on similar project."

UAF Response to Comment 8a(iv):
The transportation cost for the spent catalyst is assumed to be the same as the transportation cost for a replacement catalyst to UAF.

b. No basis is provided for the SCR freight cost of $20,000.

UAF Response to Comment 8b:
The $20,000 freight cost was based on the cost of freight for a smaller SCR application on the ACEP Generator Engine, EU 27. Please refer to the email from Erick Pomrenke at NC Power Systems to Lain Pacini on November 12, 2015 in Appendix B of the BACT analysis report. NC Power Systems states that freight costs would be in the range of $9,000 to $12,000. The BACT analysis for EU 3 assumes that the SCR system for a larger emission unit would weigh more and consequently have higher freight costs for shipment. The freight cost for an SCR system on EU 3 has been scaled up from the cost provided by NC Power Systems.

c. Initial performance testing cost is included twice.

UAF Response to Comment 8c:
The performance testing cost of $10,000 was inadvertently included twice. In the cost analysis, testing was shown under Direct Costs (1)(b) "NO_X CEMS Certification Testing" and then again under Indirect Costs (4) "Performance Tests." Correcting the cost analysis to remove the duplicate cost has minimal impact on the calculated cost effectiveness of the control system. The cost effectiveness value changes from $8,416 to $8,400 per ton of NO_X removed.

d. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual – it is not appropriate to include a 30% contingency factor based on this accuracy range.

UAF Response to Comment 8d:
The accuracy range of the Fuel Tech cost estimate is unrelated to the contingency factor. Vendors provide these accuracy ranges because the vendors know certain factors cannot be accounted for in the cost in the absence of any substantial design work. An example of this issue would be any special structural material costs to accommodate seismic requirements, which certainly exist in this application in Interior Alaska.

UAF believes that the use of the 30 percent contingency factor is appropriate due to the following elements:

- *The age of EU 3, its ancillary equipment, and the building envelope in this part of the CHPP. EU 3 was installed in 1970. Installing emission controls (or any new equipment) on this boiler in this portion of the plant requires appropriate contingency to address unforeseen issues which are likely to arise when dealing with a facility which is 50 years old.*
- *A contingency cost of 30 percent was applied to equipment and material costs, direct installation costs, and engineering and procurement costs in the BACT analysis for the SCR systems on the combustion turbines at the Exxon Mobil Point Thomson Production Facility. Please see Page 23 of the Technical Analysis Report (TAR) to Permit No. AQ1201CPT01.Consistent with that ADEC-approved analysis, UAF believes that 30 percent is an appropriate ratio for the EU 3SCR cost analysis.*
- *Because preparing a BACT analysis requires obtaining vendor pricing information without knowing the exact final emission limit, the vendor could not be provided with a precise emissions target. The vendor therefore must rely upon their general experience of what percent reduction could be achieved by an SCR system. Applying a contingency factor in the cost effectiveness evaluation seems both practical and appropriate. Use of a contingency factor for costs associated with control device retrofits is also consistent with a Boiler MACT compliance feasibility study prepared by SCI*

for a confidential client with six coal-fired boilers.

- *The use of urea requires the consideration of material handling, storage, energy requirements for dissolving urea into solution, and maintaining that liquid solution during cold weather months in Interior Alaska. These issues are all likely to result in higher costs.*

UAF notes that removing the contingency factor from the cost analysis calculation results in a cost effectiveness of $7,261/ton of NO_X removed (as opposed to $8,416/ton when including the 30 percent contingency). As discussed in Section 3.5 of the BACT analysis report, UAF believes that the cost estimate for SCR on EU 3 is low. Additionally, the actual emission reductions that would be achieved through installing SCR would be minimal (i.e., less than 6 tons per year of NO_X removed). Please refer to the response to Comment 7a above. The effective cost of installing SCR on EU 3 would be approximately $144,000 per ton of NO_X removed when considering the backup role of EU 3 and the expectation that EU 3 will continue to operate at a very low capacity factor.

9. <u>EU 3 Mid-Sized Diesel Boiler: ULSD</u> – The ULSD cost analysis is based on "review of UAF's fuel costs from FY 2011 through 2016. Average of the FY 2014 through 2016 is used, which is 28 cents per gallon more to use ULSD." The documents forming the basis for this information must be submitted in order to rely on this information for purposes of the analysis.

<u>UAF Response to Comment 9:</u>
The fuel prices used in the ULSD cost analysis were obtained from the Oil Price Information Service (OPIS) through the website at https://www.opisnet.com/.

10. <u>EU 8 Large Diesel Fired Engine: Operational Scenario</u> – The NO_X BACT analysis for this unit applies the facility-requested 40 ton per year emission limit, and bases the analysis on an assumed NO_X reduction of only 36 tons (90% reduction from 40 tpy). However, the analysis assumes that the unit operates 8,760 hours/year when calculating the annual O&M costs (i.e., see aqueous ammonia cost). The assumptions underlying the cost analysis are therefore inconsistent. The cost effectiveness analysis must be revised to be consistent based on the assumed operational scenario for the unit. For example, if the unit is assumed to operate uncontrolled for NO_X up to the 40 ton/year limit, the corresponding costs associated with only those limited number of hours may be included. This applies to all annual operating & maintenance costs, including catalyst life.

<u>UAF Response to Comment 10:</u>
EU 8 does not have an operating limit that directly restricts operating hours. As a practical matter, UAF agrees that the 40 tpy NO_X emission limit would likely result in engine operating hours which are less than 8,760 hours per year. UAF also notes that the standard methodology of preparing a BACT analysis is not realistic in this case, because the 40 tpy NO_X limit remains in effect. Requiring the use of SCR to reduce the NO_X emission rate from EU 8 will not result in an overall emissions reduction. With an emissions reduction of zero tons per year, a cost effectiveness

value cannot be calculated:

Cost effectiveness = (Total Annualized Costs, $) / (Tons of Pollutant Avoided, tpy)

If the denominator of this fraction is zero, no emission control can be determined to be cost effective and therefore BACT. As addressed in Section 3.5 of the BACT analysis report, UAF recommends that the BACT limit require the use of the existing turbocharger, aftercooler, and operations under the existing 40 tpy NO_X limit.

11. EU 8 Large Diesel Fired Engine: SCR – Please provide detailed information regarding the visible emissions described in the BACT analysis which were observed during operation of the SCR currently installed on the large diesel engine. See page 19.

UAF Response to Comment 11:
The visible emissions from EU 8 originate from the Heat Recovery Steam Generator (HRSG), not the existing SCR system. Modifications to the exhaust system would be necessary to enable use of the existing SCR system. For more information on the visible emissions concern, please refer to the Compliance Order by Consent (COBC) dated effective September 25, 2015. (ADEC Enforcement Tracking No. 12-1016-50-0002)

An amendment to the COBC was executed in April 2016 to allow operations of EU 8 following specific maintenance events as recommended by the manufacturer. EU 8 operated for 89 minutes in May 2016 following an overhaul. UAF conducted a Method 9 visible emission observation during the engine run, which indicated excess visible emissions. UAF reported the observations to ADEC as required. Otherwise, EU 8 has not been operated and cannot be operated (except for validation of maintenance events per the COBC amendment).

12. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, but provides no technical analysis or other quantitative or analytical basis for this argument. Further, the BACT analysis determines that an appropriate DPF "likely does not exist" without citing any information from established DPF equipment suppliers. The BACT analysis cites only a single local Fairbanks engine company, whose employee states that the company has "never supplied a DPF with a new engine or for aftermarket use". The information provided forms insufficient basis to reject DPF as technically infeasible and/or not cost effective. The analysis must provide detailed technical analysis of the backpressure issue by an engineering firm or control equipment supplier with the necessary expertise regarding the control technology. In order to establish the availability of a suitable DPF, the analysis must include information regarding these topics from established DPF control equipment suppliers. The availability of this control technology is not limited to DPF equipment currently available "off the shelf". UAF must explore whether manufacture of an appropriate DPF for this emission unit is technically feasible, and conduct an emission unit specific cost analysis following the EPA Cost Manual.

UAF Response to Comment 12:

EU 8 is a Fairbanks Morse Colt-Pielstick engine. Fairbanks Morse Engine (FME) is a well-established engine manufacturer with considerable technical expertise. FME is not a local Fairbanks engine company. FME is based in Wisconsin and was founded more than 140 years ago. More information on FME is available at www.fairbanksmorse.com.

According to information from an FME representative, a diesel particulate filter (DPF) device is not a commercially available technology for this engine. Please refer to the email from Joe Rubino to Julie Ackerlund of February 24, 2016 in Appendix B of the BACT analysis, which documents the discussion between SCI and FME. As stated in section 4.2.4 of the BACT analysis, the RBLC database has no entries for DPF devices installed on large diesel-fired engines. DPF is not currently technically feasible due to the backpressure which results when a filtration system is added to the exhaust stream. Because the UAF research indicates that a DPF device for EU 8 is neither commercially available nor technically feasible, a cost analysis for DPF technology will not be prepared.

Please note that UAF provided a BACT analysis for $PM_{2.5}$ direct emissions as a courtesy even though the analysis is not required. The UAF campus stationary source is not a nonattainment major source of $PM_{2.5}$, as described in Section 1.0 of the BACT analysis. As a result, direct $PM_{2.5}$ emissions do not trigger the requirement to prepare a BACT analysis, and BACT limits for $PM_{2.5}$ emissions from emission units at UAF are not required elements of the State Implementation Plan (SIP).

13. <u>EU 27 ACEP Generator</u> – The BACT analysis includes evaluations of SCR and DPF as applied individually for control of NO_X and $PM_{2.5}$ respectively, from this emission unit, however a combination SCR/DPF was not evaluated. The analysis must be revised to include a cost effectiveness analysis for this combined control technology.

<u>UAF Response to Comment 13:</u>
NC Power Systems supplied a capital cost for a combined SCR/DPF control system along with the cost estimate for the separate DPF and SCR packages. Please refer to the email from Erick Pomrenke at NC Power Systems to Lain Pacini on November 11, 2015 in Appendix B of the BACT analysis report. UAF has prepared a cost effectiveness analysis using the combined SCR/DPF capital cost. The analysis uses the existing SCR cost analysis submitted in the BACT report as a starting point and adjusts for the increased capital cost and the mass of pollutants controlled to account for a combined $NO_X/PM_{2.5}$ emission reduction. The cost effectiveness for a combined SCR/DPF is not economically feasible. The cost effectiveness is $11,340 per ton of pollutant (NO_X and $PM_{2.5}$) removed. This cost analysis is presented in Attachment A.

Please note that UAF provided a BACT analysis for $PM_{2.5}$ direct emissions as a courtesy even though the analysis is not required. The UAF campus stationary source is not a nonattainment major source of $PM_{2.5}$, as described in Section 1.0 of the BACT analysis. As a result, direct $PM_{2.5}$ emissions do not trigger the requirement to prepare a BACT analysis, and BACT limits for $PM_{2.5}$ emissions from emission units at UAF are not required elements of the SIP.

ADEC Draft Comments

12. For the purposes of this BACT analysis the cost analysis for each emissions control for each of EUs 4 and 8 should be based on the assumption that the 40 tpy NOx limit will be consumed by the EU being evaluated. Under the current permitting limit it is possible for one of EUs 4 and 8 to be the sole contributor to the 40 tpy of NOx in any given 12 month rolling period. Additionally, the 10 percent capacity limit for EU 4 was removed with the issuance of Minor Permit No. AQ0316MSS04 on August 4, 2016, and is therefore no longer applicable as limited operation for EU 4. Please revise the PTE and cost analysis for these units.

    UAF Response to ADEC Comment 12:
    The 10 percent capacity factor limit on EU 4 remains in effect. Please refer to Conditions 17 and 41.2 of Permit No. AQ0316TVP02, Revision 1, and page 20 in the Statement of Basis for the Title V permit. The capacity factor limit is an owner requested limit (ORL) which enables EU 4 to be exempt from a NO_X emission standard and monitoring requirements in the New Source Performance Standards (NSPS) in 40 Code of Federal Regulations (CFR) 60 Subpart Db. Permit No. AQ0316MSS04 was issued on February 15, 2013, and addresses EUs 9A, 19, 20, and 21. That permit did not address EU 4 and did not remove the 10 percent capacity factor limit. Permit No. AQ0316MSS05 was issued on August 4, 2016 and does not include the capacity factor limit. Per item 4 under Section 4 of the Technical Analysis Report for Permit No. AQ0316MSS05, the NSPS requirements are not included in the minor permit because those requirements have since been incorporated into the operating permit. As a result, the PTE and cost analyses for EU 4 in the BACT analysis are correctly based on the 10 percent capacity factor limit. (Refer to Tables 1-3, 1-5, 3-3, 3-13, 5-3, and 5-9 in the analysis report.)

    With respect to EU 8, baseline NO_X and SO_2 PTE are each set at 40 tpy to reflect that EU 8 could consume either or both of the entire NO_X and/or SO_2 annual emission limits. Please refer to Tables 1-2, 1-3, 1-5, 3-3, and 5-3. No revisions to the PTE or cost analyses for EU 8 are needed as a result.

13. Describe for each emission unit type, what constitutes good combustion practices. Include any work or operational practice that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

    UAF Response to ADEC Comment 13:

Emission Unit Type

- ***Mid-sized Diesel-Fired Boilers** (EUs 3 and 4) – 180.9 MMBtu/hr*
    - *Optimize air to fuel ratio.*
    - *Conduct regular maintenance.*
    - *Regular Cleaning of Boiler.*
        - *Any residue, such as soot or scale that coats the heat transfer surfaces of the boiler will reduce its efficiency and also increase the likelihood of equipment*

failure. Cleaning this surface according to manufacturer's recommendations is important to maintaining optimum boiler performance and equipment life.

- *Water Chemical Treatment*
  - *Good boiler water chemical treatment, depending on the dissolved minerals in the makeup of the water.*
  - *Poor water treatment practices can result in scale accumulation on the water side of the tubes.*
  - *Annual inspections of boilers should include a thorough examination of the water side surfaces for evidence of scaling and corrosion. Even a thin layer of scale interferes with heat transfer and thereby decreases combustion efficiency.*
- *Minimize Boiler Blowdown*
  - *Having too many total dissolved solids (TDS's) in the boiler water can cause scale and reduce boiler efficiency. Therefore, it is necessary to maintain the solids below certain limits.*
  - *Excessive blowing down will reduce useful output and lower efficiency.*

- ***Large Diesel-Fired Engine** (EU 8) – 13,266 hp*
  - *Optimize air to fuel ratio.*
  - *Operate the engine such that the following combustion air management conditions are met:*
    - *a sufficient quantity of oxygen is available to ensure complete combustion,*
    - *a sufficient amount of diluent (i.e., EGR) is present to control the combustion temperature,*
    - *the temperature and pressure (density) of the charge air is controlled,*
    - *suitable bulk motion and kinetic energy is imparted to the charge air in the cylinder to support the mixing of air, fuel and intermediate combustion products, and*
    - *the size and concentration of impurities such as dust and dirt is acceptable.*
  - *Manage the charge air temperature by:*
    - *Cooling high temperature air in boosted diesel engines and*
    - *Heating low temperature air to facilitate engine start-up and warm-up at low ambient temperatures.*
  - *Preheat engine.*
  - *Balance cylinder firing pressures.*
  - *Recirculate exhaust gas back into the intake system.*
- ***Medical/Pathological Waste Incinerator** (EU 9A)*
  - *EUs will be operated and maintained in accordance with manufacturer specification.*
- ***Small Boiler** (EUs 19 – 21)*
  - *EUs will be operated and maintained in accordance with manufacturer specification.*
- ***Small Engine** (EU 27)*
  - *EUs will be operated and maintained in accordance with manufacturer specification.*
- ***Large Coal-Fired Boiler** (EU 113) – 295.6 MMBtu/hr*
  - *Optimize air to coal ratio by reducing excess air or excess O2.*
  - *Minimize air-in leakage and air heater cross leakage to minimize fan power and flue gas heat losses.*
  - *Optimize coal fineness and moisture content based on the coal being burned in the unit.*
  - *Maintain boiler burners such that fuel distribution is evenly dispersed.*
  - *Maintain good water quality to prevent fouling of tube surfaces and poor heat transfer.*

- *Inspect and maintain insulation, boiler tubes, and access door seals.*

From: Russ Steiger
To: Koch, Denise (DEC)
Cc: Huff, Deanna M (DEC); Heil, Cynthia L (DEC); Simpson, Aaron J (DEC); hedgpeth.zach@epa.gov; Frances Isgrigg
Subject: UAF Response to EPA-ADEC comments on BACT Analysis
Date: Thursday, December 21, 2017 9:47:21 AM
Attachments: UAF Response to EPA-ADEC BACT Comments 12-21-2017.pdf

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Dear Ms. Koch:

The University of Alaska Fairbanks (UAF) received a request for additional information regarding the Best Available Control Technology (BACT) analysis from the Alaska Department of Environmental Conservation (ADEC) on October 20, 2017. This request included a set of 13 comments. ADEC provided a second set of comments and information requests from the US Environmental Protection Agency (EPA) Region 10 on November 6, 2017.

The responses to both sets of questions are on the attached document that includes an explanatory cover letter and an attachment with the responses. These documents are also being delivered to you via USPS Certified Mail.

If you have any questions or require additional information regarding this response, please feel free to contact me using the information below my signature.

Russ Steiger
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ADEC Request for Additional Information
University of Alaska Fairbanks
BACT Technical Memorandum Review
SLR Report January 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 45 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed." This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates." The 10 year equipment life assumption is based on the harsh climate, evidence of which must be provided. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. A 20 year equipment life may be used for SNCR, but a 30 year equipment life is required for the other control devices (i.e., SCR, Wet FGD, DSI, circulating dry scrubber (CDS), and SDA) unless detailed documentation can be provided.

2. Interest Rate – Page 45 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed." All cost analysis must use the current bank prime interest rate. This can be found online at; https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

3. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

4. CFB Boiler: SDA and DSI
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[2], US EPA Region 6 found that a

[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017

[2] 76 FR 81728, December 28, 2011

reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.

b. Please provide the documents for the following citations:
    i. "SCI engineering estimates (5 years old) for other SDAs."
    ii. "SCI engineering estimates (5 years old) for other DSI systems"
    iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."
    iv. "…similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

5. CFB Boiler: SNCR – Please provide documentation for the following citation in the BACT analysis: Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."

6. CFB Boiler: SCR – Please revise the cost analysis submitted using the EPA updated cost manual chapter pertaining to SCR[3]. Documentation must be provided for the following cited information:
    a. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
    b. Fab Site Vendor "days based on similar project."
    c. Onsite Vendor "days based on similar project."
    d. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."
    e. "Replacement labor based on similar project."
    f. "Labor cost based on similar project."

    The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

7. EU 3 Mid-Sized Diesel Boiler: SCR
    a. Please provide the documentation for following citations in the BACT analysis.
        i. "Replacement labor based on similar project."
        ii. Transport cost direct to site (SCR catalyst). "Based on similar project."
        iii. Transport cost for spent SCR catalyst. "Based on similar project."
    b. No basis is provided for the SCR freight cost of $20,000.
    c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

    The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

8. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

9. SO_2 Control Device: Circulating Dry Scrubber – Please include CDS in the analysis for SO_2 emission controls. It is required that all control devices are evaluated for BACT.

10. Control Technology Availability – Documentation from multiple control technology vendors must be provided in order to eliminate a control technology based on unavailability. Please provide additional information regarding the lack of availability for control technologies

[3] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

eliminated on this basis. This additional information should not be provided from the EU's manufacturer.

11. <u>Retrofitting</u> – Please provide additional information regarding technologies eliminated due to space constraints and/or complications. Detailed information must be provided in support of eliminating a control technology based on space requirements. Additionally, documentation regarding any inclusion of retrofitting cost must be provided. Please provide site-specific quotes for retrofitting requirements.

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

DIVISION OF AIR QUALITY
Director's Office

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September 13, 2018

Frances Isgrigg, Director
Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks by November 1, 2018

Dear Ms. Isgirgg:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the University of Alaska Fairbanks and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the University of Alaska Fairbanks. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Isgrigg on May 11, 2017 notifying her of the reclassification to Serious and included

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

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

Clean Air

a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis was submitted by email to ADEC on February 8, 2017 from University of Alaska Fairbanks. It included emission units found in Operating Permit AQ0316TVP02 Revision 1 and Minor Permit AQ0316MSS06 Revision 2.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for the University of Alaska Fairbanks for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from the University of Alaska Fairbanks and the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from the University of Alaska Fairbanks to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that the University of Alaska Fairbanks review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for the University of Alaska Fairbanks, it must include the determination in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies

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[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a

[5] 40. CFR 51.1010(4)

for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from the University of Alaska Fairbanks. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

BY OR

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for UAF BACT Analysis
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
March 22, 2018	UAF Comments Addressing the Preliminary Best Available Control Technology Determination for University of Alaska Fairbanks
October 20, 2017	Request for Additional Information for UAF BACT Analysis
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for UAF

cc:
Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Brittany Crutchfield, ADEC/Air Quality
Frances Isgrigg/University of Alaska Fairbanks
Dan Brown, EPA Region 10
Aaron Simpson, ADEC/Air Quality
Jim Plosay, ADEC/ Air Quality
Deanna Huff, ADEC/ Air Quality
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
    a. Page 20, paragraph 5 (or 2nd from the bottom).
    b. Page 34, Table 8. Include templates.

<u>Precursor Demonstration</u>

1. <u>Ammonia Precursor Demonstration</u> - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. <u>Sulfur Dioxide Precursor Description</u> - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

<u>BACM (and BACT), MSM</u>

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. <u>BACM/BACT and MSM: Separate Analyses</u> - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. <u>Selection of Measures and Technologies</u> - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***<u>all</u>*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. <u>Technological Feasibility</u> - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the “General” comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure “that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources.” We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion "not eligible for consideration as BACM" is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. <u>BACM and MSM, Ammonia</u> - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. <u>Backsliding Potential</u> - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. <u>Transportation Control Measures</u> - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The "date certain" removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
  - Measure R1, page 63: Natural gas fired kiln or regional kiln.
  - Measure R12, page 71: Replace uncertified stoves in rental units.
  - Measure R17, page 75: Ban use of wood stoves
  - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
  - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
  - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
   a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
   b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. Guidance Reference – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. Community Burden Estimate – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as "community burden" (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing “less sources” to “fewer sources.”

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement “ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control” is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence “This site will be included in the Serious SIP’s attainment plan…” as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98th percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "a BACT analysis is an evaluation of all technically available control technologies for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in "emission inventory" versus "emissions inventory".

Page 1: "CAA" to "Clean Air Act" for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1's calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the "winter season" inventory as the "seasonal" inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, "results in extremely high heating energy demand per square foot experienced in no other location in the lower-48."

Page 9: Please change "Violations" to "Exceedances." Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add "No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.", to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., "downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear "For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a "base" demand typically met by cleaner home heating oil when ambient temperatures get colder."

Page 19: Remove "Where appropriate,". All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change "projected forward" to "re-inventoried", or similar wording. Reserve "project" for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA's memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, "project" should be "re-inventoried" or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- o Potential typo – we believe that 2018 should be 2013.
- o Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement "first and most comprehensive systematic" would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in PM2.5 than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove "com"

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add "threshold" after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change "has decided" to "decided."

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding "… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value" to the sentence that starts "The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing "slightly" and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as "$PM_{2.5}$" not "PM".

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn't involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption “These restrictions shall not apply during a power failure.” should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for “Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, “did not know if the rule had worked well” needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists “none” under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

From: Ollila, Tera L (DEC)
To: "fisgrigg@alaska.edu"
Cc: Koch, Denise (DEC); Hartig, Lawrence L (DEC); Edwards, Alice L S (DEC); Heil, Cynthia L (DEC); Huff, Deanna M (DEC); Simpson, Aaron J (DEC); Crutchfield, Brittany M (DEC); "hamlin.tim@epa.gov"; "hedgpeth.zach@epa.gov"; Spenillo, Justin; Brown, Dan; Plosay, James R (DEC)
Subject: Request for Additional Information for the BACT Technical Memorandum for UAF
Date: Thursday, September 13, 2018 4:03:09 PM
Attachments: BACT Comment Letter UAF 09.13.18.pdf
ADEC Request for Additional Information for UAF BACT Analysis.pdf
UAF Prelim BACT Comments_F.DOCX
EPA Comments on ADEC Preliminary Draft SIP Development Materials for the....pdf
ADEC Request for Additional Information for UAF BACT Analysis.pdf
Voluntary BACT Analysis for UAF.PDF
Serious SIP BACT due date email.pdf

All recipients:

Please review or copy as required.

Thank you.

Tera L. Ollila
Administrative Assistant

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November 1, 2018

Denise Koch, Director
Division of Air Quality
Alaska Department of Environmental Conservation
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, Alaska 99811-1800

Subject: University of Alaska Fairbanks
Response to the September 13, 2018 ADEC request for additional Information for the Best Available Control Technology Technical Memorandum

Dear Ms. Koch:

Attached is the response by the University of Alaska Fairbanks to your September 13, 2018 request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks (UAF).

If you have any questions related to this response, please feel free to contact me at fisgrigg@alaska.edu

Sincerely,

FOR

Frances M. Isgrigg, PE
Director, Environmental, Health, Safety and Risk Management
University of Alaska Fairbanks
1855 Marika Road
Fairbanks, Alaska 99775-8145
P: 907-474-5487 | F: 907-474-5489 | C: 907-590-5809

Enclosures:
September 13, 2018 ADEC Request for Additional Information on UAF BACT Analysis
November 1, 2018 UAF Response to September 13, 2018 ADEC Request letter

cc: (via email) Frances Isgrigg, UAF; Cindy Heil, ADEC/Air Quality; Deanna Huff, ADEC/Air Quality; Courtney Kimball, SLR; Russ Steiger, UAF

THE STATE *of* ALASKA

GOVERNOR BILL WALKER

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September 13, 2018

Frances Isgrigg, Director
Environmental Health, Safety & Risk Management
University of Alaska Fairbanks
PO Box 758145
Fairbanks, AK 99775

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum for University of Alaska Fairbanks by November 1, 2018

Dear Ms. Isgrigg:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that the University of Alaska Fairbanks and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as the University of Alaska Fairbanks. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analysis is a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Isgrigg on May 11, 2017 notifying her of the reclassification to Serious and included

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

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

Clean Air

a request for the BACT analysis to be completed by August 8, 2017. The BACT analysis was submitted by email to ADEC on February 8, 2017 from University of Alaska Fairbanks. It included emission units found in Operating Permit AQ0316TVP02 Revision 1 and Minor Permit AQ0316MSS06 Revision 2.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for the University of Alaska Fairbanks for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from the University of Alaska Fairbanks and the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from the University of Alaska Fairbanks to assist it in making a legally and practicably enforceable BACT determination for the source.

Specifically, ADEC requests that the University of Alaska Fairbanks review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes a final BACT determination for the University of Alaska Fairbanks, it must include the determination in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a

[5] 40. CFR 51.1010(4)

for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from the University of Alaska Fairbanks. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

BY OR

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for UAF BACT Analysis
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
March 22, 2018	UAF Comments Addressing the Preliminary Best Available Control Technology Determination for University of Alaska Fairbanks
October 20, 2017	Request for Additional Information for UAF BACT Analysis
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for UAF

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Brittany Crutchfield, ADEC/Air Quality
Frances Isgrigg/University of Alaska Fairbanks
Dan Brown, EPA Region 10
Aaron Simpson, ADEC/Air Quality
Jim Plosay, ADEC/ Air Quality
Deanna Huff, ADEC/ Air Quality
Tim Hamlin, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
University of Alaska Fairbanks
BACT Technical Memorandum Review
SLR Report January 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public comment. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public comment period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

Draft Comments

1. Equipment Life – Page 45 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed." This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates." The 10 year equipment life assumption is based on the harsh climate, evidence of which must be provided. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. A 20 year equipment life may be used for SNCR, but a 30 year equipment life is required for the other control devices (i.e., SCR, Wet FGD, DSI, circulating dry scrubber (CDS), and SDA) unless detailed documentation can be provided.

2. Interest Rate – Page 45 (Adobe page number) of the analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed." All cost analysis must use the current bank prime interest rate. This can be found online at; https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

3. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

4. CFB Boiler: SDA and DSI
    a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze[2], US EPA Region 6 found that a

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[1] University of Alaska Fairbanks, Voluntary Best Available Control Technology Analysis for the Serious $PM_{2.5}$ Non-Attainment Area Classification, Prepared by SLR, January 2017

[2] 76 FR 81728, December 28, 2011

reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.

   b. Please provide the documents for the following citations:
      i. "SCI engineering estimates (5 years old) for other SDAs."
      ii. "SCI engineering estimates (5 years old) for other DSI systems"
      iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."
      iv. "...similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

5. <u>CFB Boiler: SNCR</u> – Please provide documentation for the following citation in the BACT analysis: Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."

6. <u>CFB Boiler: SCR</u> – Please revise the cost analysis submitted using the EPA updated cost manual chapter pertaining to SCR[3]. Documentation must be provided for the following cited information:
   a. "Cost of startup spares indicated as a percentage of equipment cost per similar project."
   b. Fab Site Vendor "days based on similar project."
   c. Onsite Vendor "days based on similar project."
   d. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."
   e. "Replacement labor based on similar project."
   f. "Labor cost based on similar project."

   The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

7. <u>EU 3 Mid-Sized Diesel Boiler: SCR</u>
   a. Please provide the documentation for following citations in the BACT analysis.
      i. "Replacement labor based on similar project."
      ii. Transport cost direct to site (SCR catalyst). "Based on similar project."
      iii. Transport cost for spent SCR catalyst. "Based on similar project."
   b. No basis is provided for the SCR freight cost of $20,000.
   c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

   The Department notes that records can be submitted to the Department under the provisions of the Alaska Statute dealing with confidentiality of records under AS 46.14.520.

8. <u>EU 8 Large Diesel Fired Engine: DPF and SCR</u> – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

9. <u>SO_2 Control Device: Circulating Dry Scrubber –</u> Please include CDS in the analysis for SO_2 emission controls. It is required that all control devices are evaluated for BACT.

10. <u>Control Technology Availability –</u> Documentation from multiple control technology vendors must be provided in order to eliminate a control technology based on unavailability. Please provide additional information regarding the lack of availability for control technologies

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[3] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

eliminated on this basis. This additional information should not be provided from the EU's manufacturer.

11. Retrofitting – Please provide additional information regarding technologies eliminated due to space constraints and/or complications. Detailed information must be provided in support of eliminating a control technology based on space requirements. Additionally, documentation regarding any inclusion of retrofitting cost must be provided. Please provide site-specific quotes for retrofitting requirements.

ATTACHMENT 1

The University of Alaska Fairbanks (UAF) received a request for additional information regarding the Best Available Control Technology (BACT) analysis from the Alaska Department of Environmental Conservation (ADEC) on September 13, 2018. This request included a set of 11 draft comments and a request in the body of the letter pertaining to the sulfur dioxide (SO_2) BACT determination. The comments are repeated below, followed by the UAF response to each comment in italicized font.

1. Equipment Life – Page 45 (Adobe page number) of the analysis states "a standardized ten year return on investment at seven percent interest rate is assumed." This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in interior Alaska experiences more wear and tear than equipment in moderate climates." The 10 year equipment life assumption is based on the harsh climate, evidence of which must be provided. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. A 20 year equipment life may be used for SNCR, but a 30 year equipment life is required for the other control devices (i.e., SCR, Wet FGD, DSI, circulating dry scrubber (CDS), and SDA) unless detailed documentation can be provided.

   UAF Response to Comment 1:
   Consistent with established ADEC practice and previously approved Prevention of Significant Deterioration (PSD) permitting BACT analyses, a 10-year equipment life was initially used in the calculation of the capital recovery factor for the UAF BACT analysis. This equipment life was subsequently increased to 15 years for the Emissions Unit (EU) 113 spray dryer absorber (SDA) and dry sorbent injection (DSI) BACT analyses. This 10- to 15-year equipment life timeframe is appropriate for equipment operated in the harsh Alaska climate. Two recent permits with BACT analyses based on a 10-year life are Permit No. AQ0237CPT04 (see footnote to Table B-4 of the Technical Analysis Report) and Permit No. AQ0083CPT06 (see page 24 of Technical Analysis Report). Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

   The EPA Air Pollution Control Cost Manual (sixth edition, EPA/452/B-02-001, Control Cost Manual) uses equipment lifetimes between five and 30 years. Ten, 15, and 20-year lifespans are frequently used in the manual. In the information request, ADEC states that using "a 30 year equipment life is required for the other control devices [i.e., SCR Wet FGD, DSI, circulating dry scrubber (CDS), and SDA] unless detailed documentation can be provided." UAF notes that the Control Cost Manual is a guidance document as opposed to being a regulation. UAF is not aware of a rule or rulemaking that requires the use of a specific equipment life. UAF requests that ADEC provide the regulatory citations that mandate the use of a 30-year equipment life.

   Using a 10-year equipment life timeframe is appropriate in this case because of the harsh Alaska climate. One aspect of this harsh climate is the extreme ambient temperature range that is experienced in Fairbanks. The recorded ambient temperature ranges from -66 degrees Fahrenheit

(°F) to 96 °F, a span of 162 °F. The mean ambient temperature is less than 32 °F from October to April. Another aspect of this harsh climate is the occurrence of wintertime temperature inversions and the subsequent formation of ice fog. Snowfall is also a factor in defining the harsh climate, with daily recorded snowfalls of up to 16 inches and monthly recorded snowfalls of up to 65 inches. Climate data for the Fairbanks area is provided in Attachment 2.

The result of this harsh climate is a shorter equipment life due to the stress placed on materials and operating systems. Practical experience in Interior Alaska has demonstrated that items exposed to these ambient conditions (such as exterior piping (even if insulated and/or buried), any equipment with moving parts, and exhaust stacks and vents) require more frequent routine maintenance, are prone to more frequent failure, and have a shorter useful life. The harsh climate also impacts equipment located within structures. For example, DSI sorbent (or any other material) that is delivered in winter would arrive at the outside ambient temperature. Bringing that cold material inside can result in detrimental temperature stress, condensation issues, or other impacts to the equipment that is otherwise not exposed to ambient conditions.

2. Interest Rate – Page 45 (Adobe page number) of the analysis states "a standardized ten year return on investment at seven percent interest rate is assumed." All cost analysis must use the current bank prime interest rate. This can be found online at; https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

<u>UAF Response to Comment 2:</u>
UAF notes that the Control Cost Manual is a guidance document, not a regulation. Chapter 2 of the Control Cost Manual (updated February 1, 2018) addresses the importance of using "appropriate private nominal interest rates." Use of the bank prime rate is presented as an option if firm-specific nominal interest rates cannot be estimated or verified. UAF does not currently have sufficient information about potential interest rates to enable the selection of a specific interest rate for a UAF project. While UAF does not necessarily agree that the bank prime rate is the most appropriate rate, the cost analyses have been revised to reflect the current bank prime interest rate of 5.25 percent per year. UAF obtained the rate of 5.25 percent from the H.15 release (October 23, 2018) on the Federal Reserve website (https://www.federalreserve.gov/releases/h15/). The table below provides the resulting cost effectiveness values in terms of dollar per ton of pollutant avoided.

Applicable Table in UAF Voluntary BACT Analysis	Emissions Unit	Control Device	Project Life	Cost Effectiveness ($ per ton avoided) at 5.25% interest
3-5	113	SCR	10[a]	$27,013
			20[a]	$20,673
3-7	113	SNCR	10	$9,547
3-9	3	SCR	10	$8,086
3-11	3	LNB/FGR	10	$3,396
3-13	4	LNB/FGR	10	$176,906
3-15	8	SCR	10	$26,244
3-17	27	SCR	10	$11,985
4-5	19, 20, 21	PM Scrubber	10	$44,135
4-7	27	DPF	10	$18,239
4-9	9A	Fabric Filter	10	$709,916
5-5	113	SDA	10[b]	$12,992
			15[b]	$10,824
5-7	113	DSI	10[b]	$8,464
			15[b]	$8,032
5-8	3	ULSD	N/A	$1,084
5-9	4	ULSD	N/A	$1,082
5-10	8	ULSD	N/A	$971
N/A	27	SCR/DPF combination[c]	10	$10,990

Notes:
[a] A 10-year life was used in the BACT analysis that UAF provided to ADEC in January 2017. Costs based on a 20-year life were provided in the December 2017 UAF response to an ADEC information request.
[b] A 10-year life was used in the BACT analysis that UAF provided to ADEC in January 2017. Costs based on a 15-year life were provided in the December 2017 UAF response to an ADEC information request.
[c] This technology was not addressed in the BACT analysis that UAF provided to ADEC in January 2017. The cost for combined SCR and DPF for EU 27 was provided in the December 2017 UAF response to an ADEC information request.

3. CFB Boiler: Wet Scrubbing – Clearly explain the basis for excluding wet scrubbing in the BACT analysis.

UAF Response to Comment 3:
Please note that UAF addressed a similar question in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

Wet scrubbing is an older technology that has been in existence for approximately 100 years.

Wet scrubbers are expensive, difficult to maintain, require a large footprint, and require high water consumption. Pulverized coal boilers have been equipped with wet scrubbers as post-combustion SO_2 emission controls. Wet scrubbing was not included in the UAF BACT analysis because the UAF boiler is not a pulverized coal boiler. The UAF boiler EU 113 is a circulating fluidized bed (CFB) boiler. The CFB boiler design is a relatively new technology that has been developed and operated in the past few decades. The CFB boiler design is unique in that the scrubbing SO_2 control technology is not post-combustion, but is an integral part of the boiler design. The CFB boiler includes a limestone injection system. The coal is mixed with the limestone to absorb SO_2 emissions as the combustion air passes through the bed.

Wet scrubbing has not been demonstrated in practice for CFB boilers. Because the BACT analysis cannot redefine the source, such as switching a CFB boiler to a pulverized coal boiler, wet scrubbing is not an appropriate technology and was not examined in the UAF SO_2 BACT analysis.

4. CFB Boiler: SDA and DSI
   a. As part of their Oklahoma Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) final rule for regional haze, US EPA Region 6 found that a reasonable estimate for equipment life is 30 years for SO_2 control technologies, please provide a detailed explanation for the equipment life listed for the SDA and DSI control technologies.

      UAF response to Comment 4a:
      For the reasons discussed in the response to ADEC Comment 1 and provided below, UAF continues to believe that using a 30-year equipment life is not appropriate for SDA and DSI emission control systems as applied to EU 113. As a courtesy, UAF previously re-calculated the cost analysis for SDA and DSI as applied to EU 113 using a 15-year equipment life instead of the 10-year equipment used in the initial BACT analysis provided to ADEC. These recalculated cost effectiveness values were provided to ADEC on December 21, 2017. For SDA, the cost effectiveness would be $11,598 per ton of SO_2 emissions avoided. For DSI, the cost effectiveness would be $8,186 per ton of SO_2 emissions avoided. (Please see the response to ADEC Comment 2 for the cost effectiveness values calculated using the current bank prime interest rate.)

      ADEC cited a proposed federal rulemaking addressing a regional haze determination from EPA Region 6 to support a 30-year equipment life for SDA and DSI. The preamble to that proposed rule includes a discussion of equipment life for SO_2 scrubbers. The preamble states that a prior Oklahoma Federal Implementation Plan (FIP) used a lifetime of 30 years to determine costs for SO_2 scrubbers. As explained in the response to Comment 1, expanding the use of the Oklahoma FIP 30-year equipment life to the EU 113 is not appropriate because the suitability and design of equipment installed in Oklahoma is not the same as the suitability and design of equipment that would be installed in Interior Alaska. This conclusion is consistent with the basic premise that each BACT determination is to be made on a case-by-case basis. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC *comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.*

As a point of clarification, the Control Cost Manual does not indicate the use of a 30-year equipment life for any SO_2 emission control systems. Instead, the Control Cost Manual, Section 5.2, Chapter 1, paragraph 1.5.2, provides a 15-year equipment life for a wet scrubber, and cites Section 1 of the manual regarding capital recovery costs. The EPA Region 6 use of a 30-year life for SO_2 scrubbers is not consistent with the Control Cost Manual.

A 30-year equipment life for SDA and DSI as applied to EU 113 is inconsistent with EPA long-standing guidance regarding equipment life determinations. The 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting states on page b.10 of Appendix B that "The economic life of a control system typically varies between 10 to 20 years and longer ***and*** *should be determined consistent with data from EPA cost support documents and the IRS Class Life Asset Depreciation Range System." (Emphasis added.) EU 113 will be a co-generation boiler that will produce steam for campus heat and steam for the generation of electricity. Table B-1 of IRS Publication 946 (2016) provides a class life, or a tax cost recovery period, of 22 years for assets associated with Industrial Steam and Electric Generation and/or Distribution Systems (see Asset Class 00.4). Based on this information, a 30-year equipment life is not consistent with the EPA policy that the economic life of an emission control system should also be consistent with the IRS Class Life Asset Depreciation Range System.*

The conclusion is that the EPA Region 6 decision is not a mandate to base all future SDA and DSI BACT analyses on a 30-year equipment lifespan because:

- *BACT is determined on a case-by-case basis that incorporates site specific conditions;*
- *The EPA Control Cost Manual does not support a 30-year equipment for SDA and DSI; and*
- *EPA Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NA-NSR) guidance does not support a 30-year equipment for SDA and DSI.*

b. Please provide the documents for the following citations:
    i. "SCI engineering estimates (5 years old) for other SDAs."

UAF response to Comment 4b(i):
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, Stanley Consultants, Inc. (SCI), for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the

document under the confidential business information (CBI) provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

ii. "SCI engineering estimates (5 years old) for other DSI systems"

UAF response to Comment 4b(ii):
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, SCI, for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

iii. "Internal SDA cost study done by SCI in 2010, which indicated 8%."

UAF response to Comment 4b(iii):
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, SCI, for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

iv. "...similar internal SCI SDA cost analysis and other vendor (FTEK SCR) quotes."

UAF response to Comment 4b(iv):
These estimates were based on a Boiler MACT compliance feasibility study prepared by UAF's consultant, SCI, for a separate, confidential client. Because the client is not UAF and is confidential, SCI is not able to provide the estimate to UAF This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that use of the engineering estimate is appropriate and further documentation is not necessary.

The FTEK SCR quote was provided in Appendix B of the BACT analysis report.

5. CFB Boiler: SNCR – Please provide documentation for the following citation in the BACT

analysis: Indirect capital costs "18% was used in similar SCR BACT analysis. Assume same amount for SNCR."

UAF Response to Comment 5:
Per the EPA Control Cost Manual, Section 4 (NO_X Controls) Table 1.4: Capital Cost Factors for an SNCR Application (effective at the time of the UAF BACT Analysis), the indirect capital cost is listed as 20 percent of the direct capital cost (DCC). Specifically, Table 2.5 lists general facilities as 5 percent of the DCC, engineering and home office fees as 10 percent of the DCC, and process contingency as 5 percent of the DCC, for a total of 20 percent. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

UAF was conservative in the EU 113 SNCR cost analysis, using indirect capital costs as 18 percent of the direct capital costs. This ratio is consistent with the ExxonMobil Point Thomson Production Facility BACT analysis for SCR systems on combustion turbines, which used vendor data for indirect capital costs and not the EPA Control Cost Manual capital cost factors. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the use of a recent ADEC-approved estimate ratio for determining indirect costs is sufficient, and that further documentation is not necessary.

6. CFB Boiler: SCR – Please revise the cost analysis submitted using the EPA updated cost manual chapter pertaining to SCR. Documentation must be provided for the following cited information:
   a. "Cost of startup spares indicated as a percentage of equipment cost per similar project."

      UAF Response to Comment 6a:
      The cost of startup spares was estimated as a percentage of equipment cost in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the cost for startup spare equipment estimated at 0.50 percent of total equipment costs is reasonable, and that further documentation is not necessary.

   b. Fab Site Vendor "days based on similar project".

      UAF Response to Comment 6b:
      The fabrication site vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI

provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that these vendor fees are reasonable, and that further documentation is not necessary.

c. Onsite Vendor "days based on similar project".

<u>UAF Response to Comment 6c:</u>
The onsite vendor representative fees were assumed to be comparable to those fees from a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that these vendor fees are reasonable, and that further documentation is not necessary.

d. Indirect capital costs "18% was used in similar SCR BACT analysis for smaller CTs."

<u>UAF Response to Comment 6d:</u>
Per the EPA Control Cost Manual, Section 4 (NO_X Controls) Table 1.4: Capital Cost Factors for an SNCR Application (effective at the time of the UAF BACT Analysis), the indirect capital cost is listed as 20 percent of the DCC. Specifically, Table 2.5 lists general facilities as 5 percent of the DCC, engineering and home office fees as 10 percent of the DCC, and process contingency as 5 percent of the DCC, for a total of 20 percent. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

UAF was conservative in the EU 113 SCR cost analysis, using indirect capital costs as 18 percent of the direct capital costs. This ratio is consistent with the ExxonMobil Point Thomson Production Facility BACT analysis for SCR systems on combustion turbines, which used vendor data for indirect capital costs and not the EPA Control Cost Manual capital cost factors. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the use of a recent ADEC-approved estimate ratio for determining indirect costs is sufficient, and that further documentation is not necessary.

e. "Replacement labor based on similar project."

<u>UAF Response to Comment 6e:</u>
The catalyst replacement labor hours were assumed to be comparable to those labor hours determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the labor

hour estimate is appropriate, and that further documentation is not necessary.

f. "Labor cost based on similar project."

UAF Response to Comment 6f:
The catalyst replacement labor rate was assumed to be comparable to the catalyst replacement labor rate determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. The labor rate used in the analysis is likely conservatively low because the cost is not reflective of 2018 labor rates. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes the rate is representative of labor costs, and that further documentation is not necessary.

7. EU 3 Mid-Sized Diesel Boiler: SCR
   a. Please provide the documentation for following citations in the BACT analysis.
      i. "Replacement labor based on similar project."

      UAF Response to Comment 7a(i):
      The catalyst replacement manhours and labor rate were assumed to be comparable to the manhours determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the labor hour cost estimate for catalyst replacement is appropriate, and that further documentation is not necessary.

      ii. Transport cost direct to site (SCR catalyst). "Based on similar project."

      UAF Response to Comment 7a(ii):
      The catalyst transportation cost was assumed to be comparable to transport costs determined in a similar project. The UAF consultant has indicated that the project was prepared for a confidential client. This documentation is client confidential and cannot be provided to UAF or the agency. UAF is not able to submit the document under the CBI provisions because the underlying estimate is not available to UAF. For the purposes of a study-level cost estimate for a BACT analysis, UAF believes that the catalyst transport cost estimate is appropriate, and that further documentation is not necessary.

      iii. Transport cost for spent SCR catalyst. "Based on similar project."

UAF Response to Comment 7a(iii):
The transportation cost for the spent catalyst is assumed to be the same as the transportation cost for a replacement catalyst to UAF. Transportation costs are not typically dependent on the direction of travel. As a result, the analysis assumes that the cost of shipping the catalyst from the vendor to UAF will be the same as the cost of shipping the spent catalyst from UAF to the vendor.

b. No basis is provided for the SCR freight cost of $20,000.

UAF Response to Comment 7b:
UAF addressed a similar question in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

The $20,000 freight cost was based on the cost of freight for a smaller SCR application on the ACEP Generator Engine, EU 27. Please refer to the email from Erick Pomrenke at NC Power Systems to Lain Pacini on November 12, 2015 in Appendix B of the BACT analysis report. NC Power Systems stated that freight costs would be in the range of $9,000 to $12,000. The BACT analysis for EU 3 assumes that the SCR system for a larger emissions unit would weigh more and consequently have higher freight costs for shipment. The freight cost for an SCR system on EU 3 has been scaled up from the cost provided by NC Power Systems.

UAF believes that the estimated $20,000 freight cost is reasonable for purposes of this study-level cost analysis. UAF notes that deleting the freight cost from the analysis would result in a cost-effectiveness value that differs by less than $100 per ton of air pollutant removed. In other words, removing the freight cost from the analysis would alter the result of the analysis by less than one percent.

c. The budgetary nature of the costs provided by FuelTech (+/- 30%) is reflected in the nature of the cost effectiveness analysis methodology established in the EPA Cost Manual, provide justification for 30% contingency factor.

UAF Response to Comment 7c:
The Fuel Tech cost estimate was provided for budgetary purposes and without Fuel Tech conducting an on-site inspection. Due to the nature of the cost estimate, Fuel Tech included an accuracy range for the cost estimate. This range was +/- 20 percent for equipment capital costs and +/- 30 percent for installation costs. The Fuel Tech cost estimate values used in the BACT analysis were as quoted and did not include any additional markup or changes. In other words, the Fuel Tech cost estimate values as used in the BACT analysis were not adjusted to incorporate the cost estimate accuracy range. Please note that UAF addressed similar questions in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

Consistent with the EPA Control Cost Manual, a 30 percent contingency factor was applied in calculating the total capital investment. Because the cost estimate accuracy range was not included in the BACT analysis, only a single 30 percent contingency factor was used in the BACT analysis.

8. EU 8 Large Diesel Fired Engine: DPF and SCR – The BACT analysis identifies back pressure as a potential technical challenge of installing a DPF to a large diesel engine such as EU 8, please provide a technical analysis basis for this statement.

   UAF Response to Comment 8:
   UAF addressed a similar question in the December 21, 2017 response to EPA Region 10 and ADEC comments on the UAF BACT analysis. The information presented here is in addition to the previously provided information.

   Engine exhaust back pressure is the exhaust gas pressure that is provided by the engine to overcome the resistance of the exhaust system in order to discharge the exhaust into the atmosphere. Installing a diesel particulate filter (DPF) increases the exhaust back pressure. To compensate for the increase in back pressure, the engine must compress the exhaust gases to a higher pressure which involves additional mechanical work. Maximum allowable engine exhaust back pressure is inversely related to engine size. The larger the engine is, the lower the allowable exhaust back pressure can be.

   Because of the very large engine capacity of EU 8, (13,266 hp), the back pressure allowed by the engine manufacturer is very low. The reason for limiting the allowable back pressure in large engines is caused by the technical challenges that result from increased back pressure. These challenges include additional mechanical work and/or less energy extracted by the exhaust system which can adversely affect intake manifold boost pressure, an increase in fuel consumption, an increase in NOx, PM, and CO emissions, and the overheating of exhaust valves.

   DPFs are not commercially available for large capacity engines because the back pressure that would be created as a result of installing a DPF would exceed the maximum allowable back pressure specified by the engine manufacturer. Exceeding the maximum allowable back pressure would not allow the engine to operate as manufactured.

9. SO_2 Control Device: Circulating Dry Scrubber – Please include CDS in the analysis for SO_2 emission controls. It is required that all control devices are evaluated for BACT.

   UAF Response to Comment 9:
   The CFB boiler design includes integrated dry scrubbing control technology. The CFB boiler incorporates dry scrubbing technology by way of the limestone injection system that is inherent to the CFB design. The RACT/BACT/LAER Clearinghouse (RBLC) database does not list any applications of CDS used with CFB boilers. The RBLC lists only one industrial coal-fired boiler which uses CDS. That boiler is a pulverized coal (PC) boiler with a capacity of approximately 20

times larger than EU 113. As a result, CDS is not demonstrated in practice for CFB boilers and does not meet the criteria of an available control technology. Developing a detailed analysis to support this conclusion is not necessary.

With respect to the other boilers at UAF (EUs 3, 4, and 19 through 21), it is inherently obvious that firing ultra-low sulfur diesel (ULSD) fuel would reduce SO_2 emissions to a greater extent and would be significantly less expensive than adding post-combustion controls.

10. <u>Control Technology Availability</u> – Documentation from multiple control technology vendors must be provided in order to eliminate a control technology based on unavailability. Please provide additional information regarding the lack of availability for control technologies eliminated on this basis. This additional information should not be provided from the EU's manufacturer.

    <u>UAF Response to Comment 10:</u>
    Providing the requested documentation is not necessary because the unavailability of the cited emission control technologies is well established through databases such as the RACT/BACT/LAER Clearinghouse. Obtaining negative declarations of equipment availability from control technology vendors is not necessary because the UAF emissions unit manufacturers and engineers are experts who are well-versed in the available emission control technologies. As a result, UAF believes that the previously provided rationale, including any information from emissions unit manufacturers, is adequate to support the determinations that certain emission control technologies are unavailable.

11. <u>Retrofitting</u> – Please provide additional information regarding technologies eliminated due to space constraints and/or complications. Detailed information must be provided in support of eliminating a control technology based on space requirements. Additionally, documentation regarding any inclusion of retrofitting cost must be provided. Please provide site-specific quotes for retrofitting requirements.

    <u>UAF Response to Comment 11:</u>
    The recent construction of EU 113, including the building that houses that emissions unit, has expanded the footprint of the UAF power plant. The result of this larger footprint is that no space remains at the power plant site for a new building to house a selective catalytic reduction (SCR) system or any other new emission control systems at grade level. Please refer to the site plan drawings in Attachment 3. This lack of available space is self-evident based on visual inspection of the site and good engineering judgement. Developing detailed information and a detailed analysis is not needed to support this common sense conclusion.

    Because of the space constraints, retrofitting requirements and costs cannot be easily defined or developed. As noted above, no space exists for installing new emissions control systems at grade. The lack of available space to accommodate emission control equipment affects not only EU 113, but EU 4 as well. Plan drawings of the building enclosing EU 4 are provided in Attachment 4. The drawings demonstrate that the building enclosure does not provide sufficient space to add an

SCR control system for EU 4, as discussed in the BACT analysis UAF submitted in January 2017. Common sense dictates that installing retrofitted equipment on existing roofs or above existing structures is prohibitively expensive because the existing structures are not designed to bear the additional weight and provide safe access to the new equipment. As a result, any retrofit design would involve prohibitively expensive modification and/or reconstruction of existing structures.

12. Request in ADEC letter dated September 13, 2018 - Specifically, ADEC requests that the University of Alaska Fairbanks review the cost effectiveness spreadsheet provided as a part of the preliminary SO_2 BACT determination which was originally developed by Sargent & Lundy (S&L) in 2010. The spreadsheet includes a link to the S&L white paper that provides a basis for the cost effectiveness calculations and indicates that the model is intended to calculate estimated total project cost (total capital cost of installation), as well as direct and indirect annual operating costs. These calculations are largely based on the estimated usage of sorbent and the gross generating capacity of the plant. Please use this spreadsheet to calculate the cost effectiveness of SO_2 removal in dollars per ton and identify all assumptions and technical justifications used in the analysis.

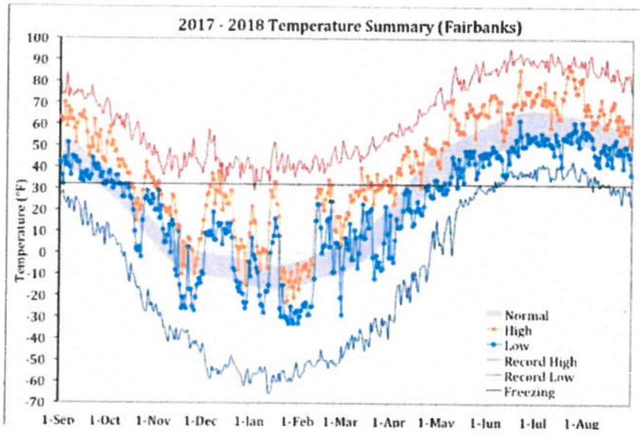
UAF Response to Comment 12:

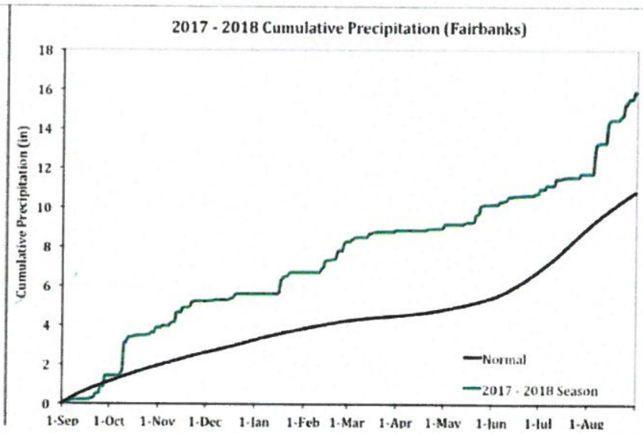
UAF is not able to review the Sargent and Lundy (S&L) cost effectiveness spreadsheet and calculations as ADEC has requested because ADEC did not provide the S&L cost effectiveness spreadsheet to UAF for review. In May 2018, UAF submitted comments to ADEC addressing the preliminary BACT determination. Those comments included a discussion indicating that Step 4 of the preliminary SO_2 BACT determination for EU 113 did not include an economic analysis. As a result, UAF was not able to determine the methodology ADEC used to calculate the cost-effectiveness for the SO_2 emission control technologies and so was not able to provide further comment at that time. At this time, UAF does not have enough information to determine whether the S&L cost model is appropriate for any emissions units at UAF, or whether the cost model is appropriate for boilers at a heat and power plant.

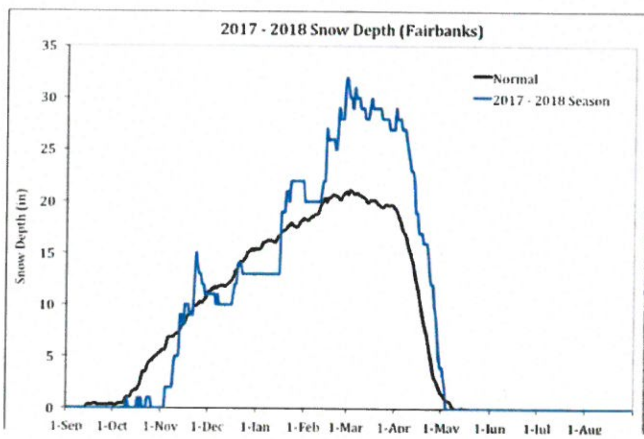
ATTACHMENT 2

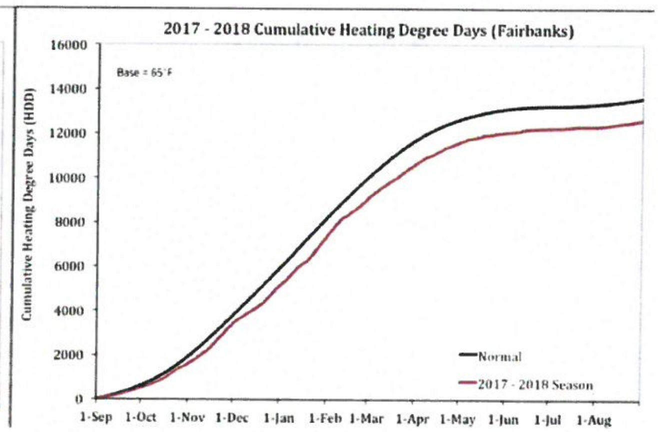
THE ALASKA CLIMATE RESEARCH CENTER

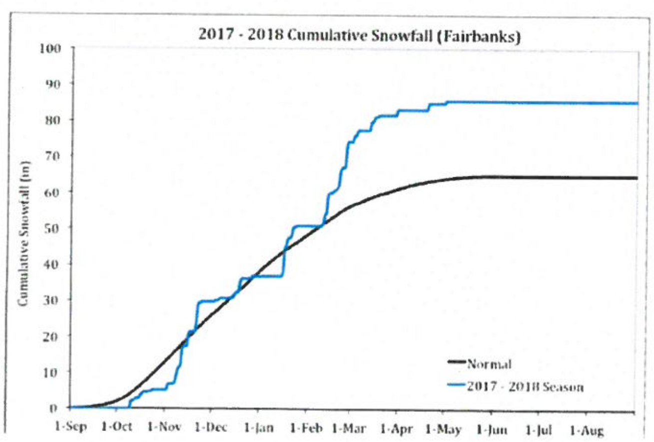
Fairbanks AP











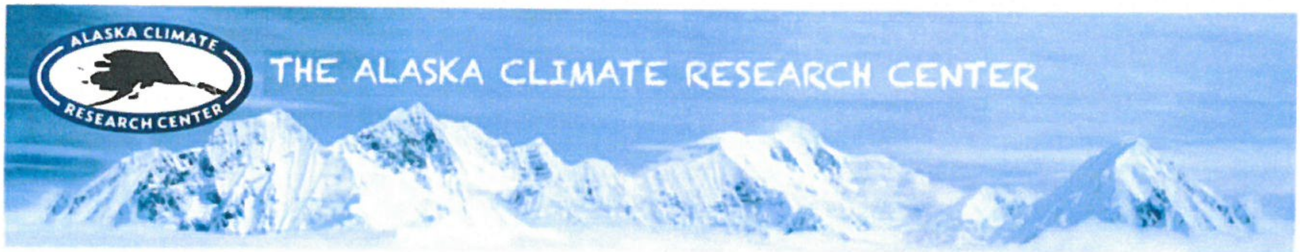
Normal	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Minimum	-16.9	-12.7	-2.5	20.6	37.8	49.3	52.3	46.4	35.1	16.5	-5.7	-12.9
Mean	-7.9	-1.3	11.4	32.5	49.4	60.4	62.5	56.1	44.9	24.2	2.6	-4.1
Mean Maximimum	1.1	10.0	25.4	44.5	61.0	71.6	72.7	65.9	54.6	31.9	10.9	4.8
Mean Precipitation	0.58	0.42	0.25	0.31	0.60	1.37	2.16	1.88	1.10	0.83	0.67	0.64
Snowfall	10.3	8.1	4.9	2.9	0.9	0.0	0.0	0.0	1.8	10.8	13.2	12.1
CDD	0	0	0	0	1	23	31	6	0	0	0	0
HDD	2260	1858	1660	974	485	160	108	281	605	1265	1872	2141

Temperature Extremes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Highest Daily Maximum (°F)	52	50	56	76	90	96	94	93	84	72	54	58
Year	2009	1943	1994	2009	1947	1969	1975	1994	1957	2003	1936	1934
Lowest Daily Minimum (°F)	-66	-58	-49	-32	-1	29	34	23	3	-28	-46	-62
Year	1934	1947	1956	1944	1964	2006	1934	1947	1992	1935	1990	1961
Highest Mean (°F)	18.1	15.93	27.08	43.67	55.58	66.85	68.37	62.56	52.75	37.81	20.13	7.65
Year	1981	1980	1981	1940	2005	2004	1975	1977	1995	1938	1979	1985
Lowest Mean (°F)	-31.68	-25.27	-6.65	17.95	38.61	51.63	55.5	49.77	31.65	13.19	-10.5	-28.15
Year	1971	1979	1959	2013	1964	1949	1959	1969	1992	1996	1963	1956

Precipitation Extremes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Highest 1-Day Maximum Precipitation (in)	1.33	0.86	0.87	0.92	0.78	1.38	2.27	3.42	1.21	1.17	0.91	0.94
Year	1937	1966	1963	2002	1992	1955	2003	1967	1954	1946	1935	1990
Highest Total Precipitation (in)	6.71	2.1	2.1	3.06	1.96	3.55	5.96	6.88	3.05	3.4	3.32	3.23
Year	1937	1944	1963	2002	2004	1949	2003	1930	1960	1935	1970	1984
Lowest Total Precipitation (in)	0.01	0.01	0.02	0.01	0.04	0.19	0.06	0.24	0.12	0.08	0.05	0.04
Year	1966	1976	2003	1944	2011	1966	2009	2005	1949	1954	2002	1952

Snow Extremes	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Highest 1-Day Maximum Snow (in)	15.5	16	12.6	10.8	9.4	1.2	0	0.1	7.8	12.5	14.6	12.9
Year	1937	1966	1963	1948	1992	1931	1930	1995	1992	1946	1970	1965
Highest Total Snow (in)	65.6	43.1	30.4	25.1	14.1	1.2	0	0.1	24.4	26.2	54	50.7
Year	1937	1966	1991	1948	1992	1931	1930	1995	1992	1935	1970	1984
Lowest Total Snow (in)	0.7	0.2	0.1	0.1	0	0	0	0	0	0.7	0.2	0.4
Year	1966	2000	1968	1954	1936	1930	1930	1930	1934	2013	1953	1952

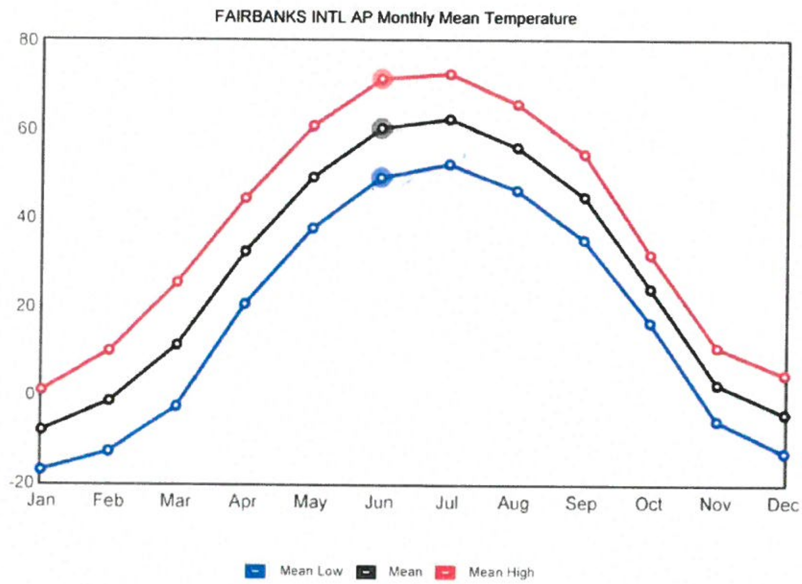
P.O Box 757320 Fairbanks, Alaska 99775-7320
A Recognized State Climate Office - American Association of State Climatologists

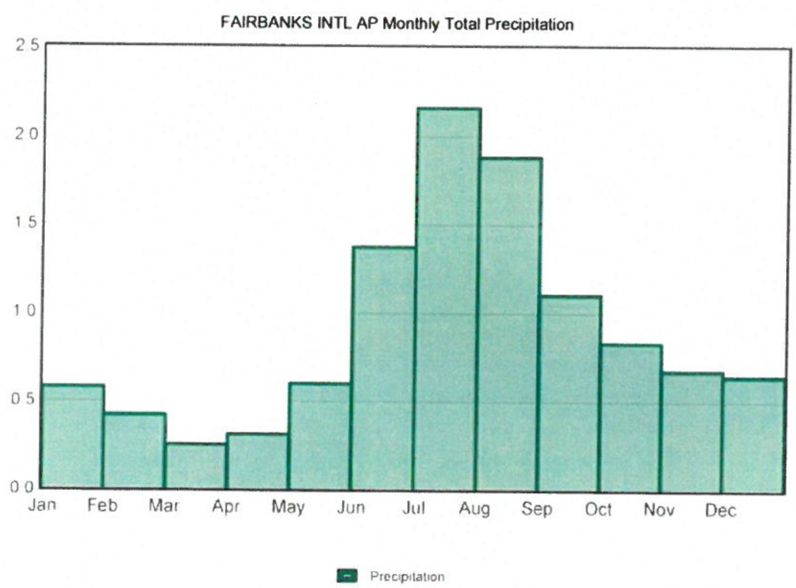


Alaska Climographs

These are the mean monthly maximum and minimum temperature and total precipitation for the period 1981 - 2010 for the first order stations in Alaska using the climatic normals provided by the National Climatic Data Center. The normals products you'll find here represent average conditions over the most recent climate normal period (1981 - 2010).

FAIRBANKS INTL AP





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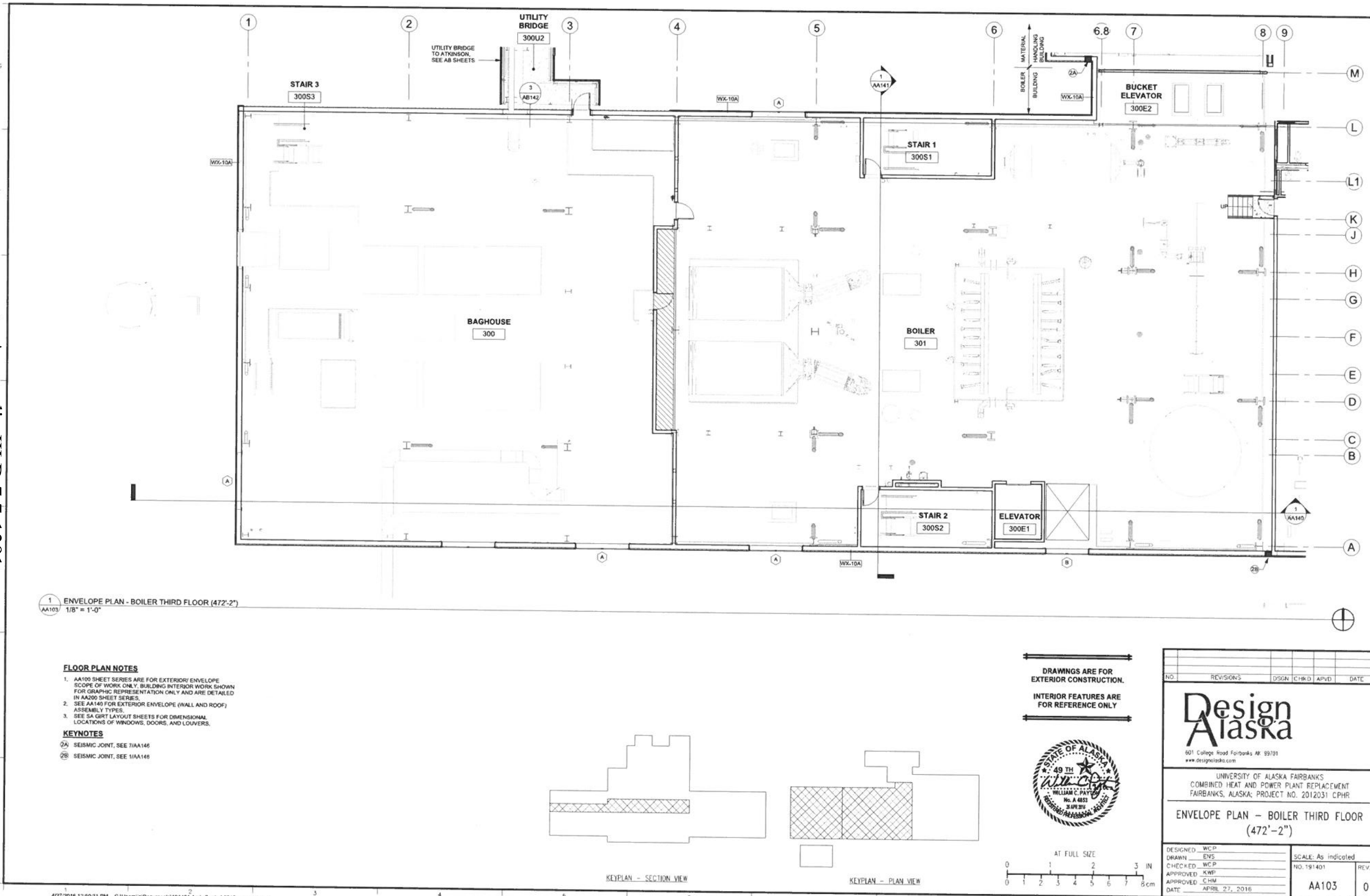
ATTACHMENT 3


UTILITY BRIDGE
300U2
UTILITY BRIDGE TO ATKINSON, SEE AB SHEETS
STAIR 3
300S3
STAIR 1
300S1
BOILER MATERIAL HANDLING BUILDING
BOILER BUILDING
BUCKET ELEVATOR
300E2
BAGHOUSE
300
BOILER
301
STAIR 2
300S2
ELEVATOR
300E1
WX-10A
UP
1 ENVELOPE PLAN - BOILER THIRD FLOOR (472'-2")
AA103 1/8" = 1'-0"
FLOOR PLAN NOTES
1. AA100 SHEET SERIES ARE FOR EXTERIOR/ ENVELOPE SCOPE OF WORK ONLY, BUILDING INTERIOR WORK SHOWN FOR GRAPHIC REPRESENTATION ONLY AND ARE DETAILED IN AA200 SHEET SERIES.
2. SEE AA140 FOR EXTERIOR ENVELOPE (WALL AND ROOF) ASSEMBLY TYPES.
3. SEE SA GIRT LAYOUT SHEETS FOR DIMENSIONAL LOCATIONS OF WINDOWS, DOORS, AND LOUVERS.
KEYNOTES
2A SEISMIC JOINT, SEE 7/AA146
2B SEISMIC JOINT, SEE 1/AA146
KEYPLAN - SECTION VIEW
KEYPLAN - PLAN VIEW
DRAWINGS ARE FOR EXTERIOR CONSTRUCTION.
INTERIOR FEATURES ARE FOR REFERENCE ONLY
STATE OF ALASKA
49 TH
WILLIAM C. PAYTON
No. A 4853
AT FULL SIZE
0 1 2 3 IN
0 1 2 3 4 5 6 7 8cm
NO. REVISIONS DSGN CHKD APVD DATE
Design Alaska
601 College Road Fairbanks AK 99701
www.designalaska.com
UNIVERSITY OF ALASKA FAIRBANKS
COMBINED HEAT AND POWER PLANT REPLACEMENT
FAIRBANKS, ALASKA; PROJECT NO. 2012031 CPHR
ENVELOPE PLAN - BOILER THIRD FLOOR
(472'-2")
DESIGNED WCP
DRAWN ENS
CHECKED WCP
APPROVED KWP
APPROVED CHM
DATE APRIL 27, 2016
SCALE: As indicated
NO. 191401
REV.
AA103
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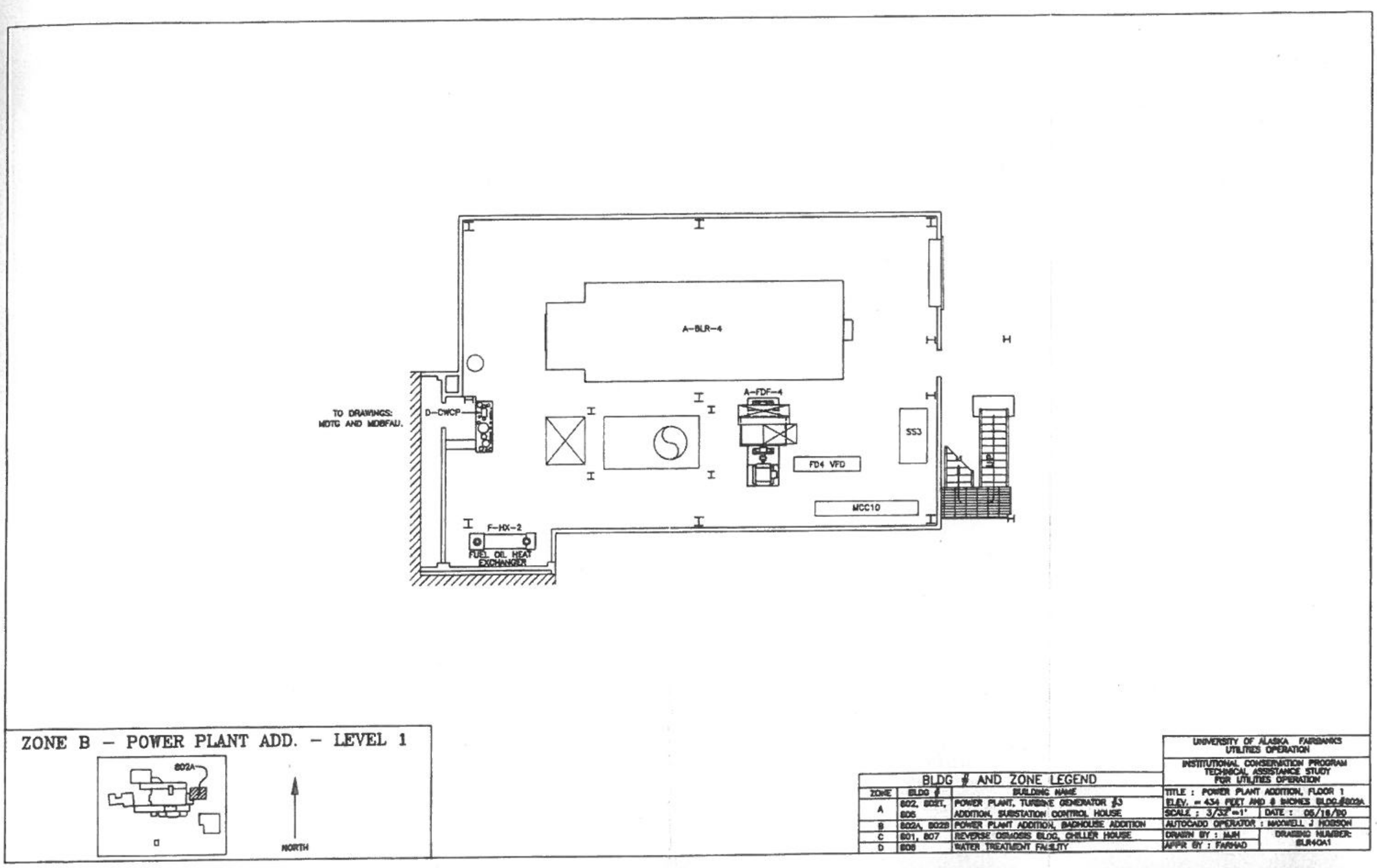
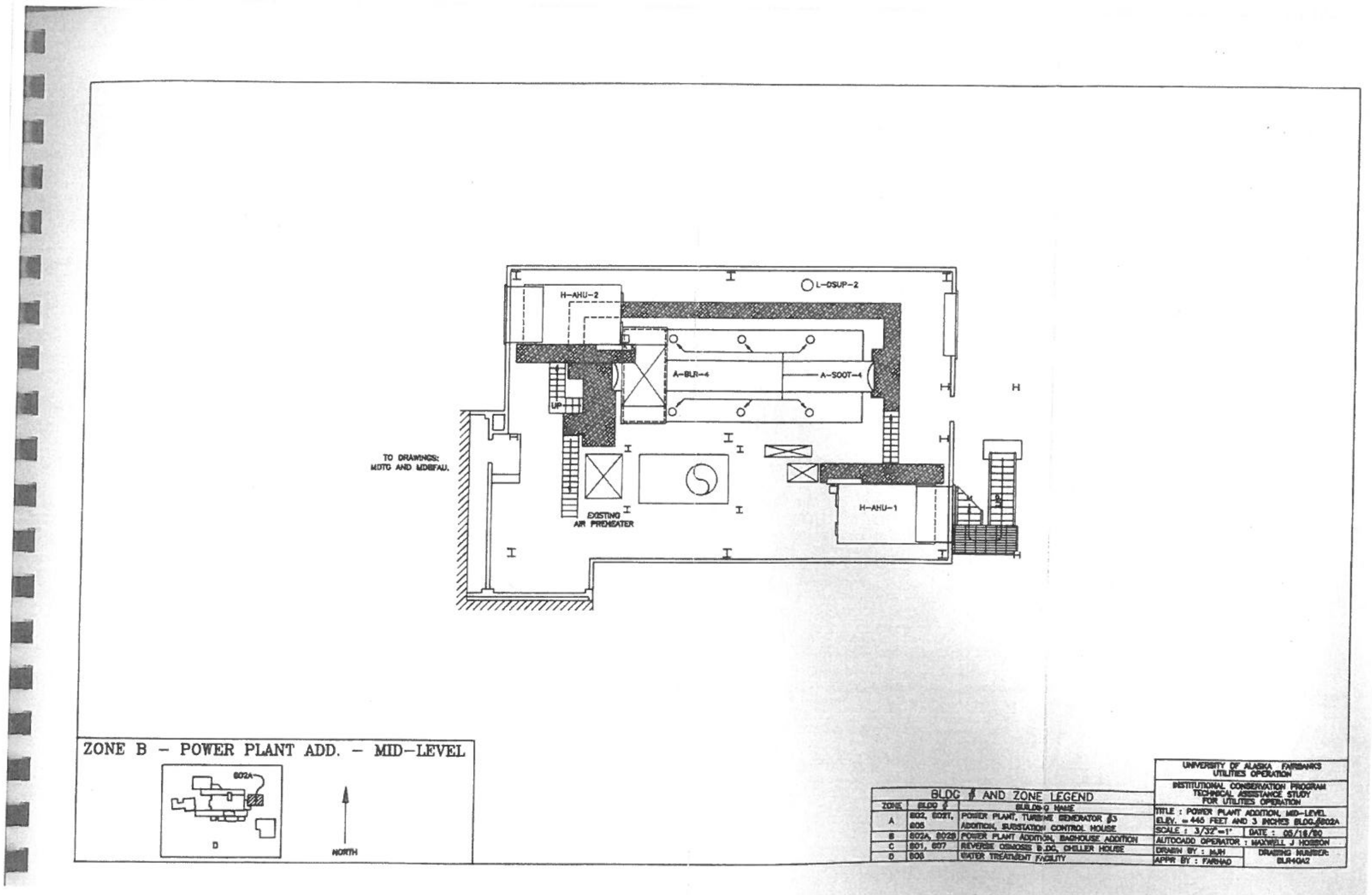
4/27/2016 12:50:31 PM C:\Users\jc\Documents\191401 Arch Central 2015_ens-spare.rvt

ATTACHMENT 4


A-BLR-4
A-FDF-4
D-CWCP
TO DRAWINGS:
MDTG AND MDBFAU.
SS3
FD4 VFD
MCC10
UP
F-HX-2
FUEL OIL HEAT
EXCHANGER
ZONE B - POWER PLANT ADD. - LEVEL 1
802A
NORTH
BLDG # AND ZONE LEGEND
ZONE | BLDG # | BUILDING NAME
A | 802, 802T, 806 | POWER PLANT, TURBINE GENERATOR #3 ADDITION, SUBSTATION CONTROL HOUSE
B | 802A, 802B | POWER PLANT ADDITION, BAGHOUSE ADDITION
C | 801, 807 | REVERSE OSMOSIS BLDG, CHILLER HOUSE
D | 808 | WATER TREATMENT FACILITY
UNIVERSITY OF ALASKA FAIRBANKS
UTILITIES OPERATION
INSTITUTIONAL CONSERVATION PROGRAM
TECHNICAL ASSISTANCE STUDY
FOR UTILITIES OPERATION
TITLE : POWER PLANT ADDITION, FLOOR 1
ELEV. = 434 FEET AND 8 INCHES BLDG #802A
SCALE : 3/32"=1'
DATE : 05/18/90
AUTOCADD OPERATOR : MAXWELL J HOBSON
DRAWN BY : MJH
APPR BY : FARHAD
DRAWING NUMBER:
BLR4OA1


H-AHU-2
L-DSUP-2
A-BLR-4
A-SOOT-4
UP
TO DRAWINGS:
MDTG AND MDBFAU.
EXISTING
AIR PREHEATER
H-AHU-1
UP
ZONE B - POWER PLANT ADD. - MID-LEVEL
802A
D
NORTH
BLDG # AND ZONE LEGEND
ZONE | BLDG # | BUILDING NAME
A | 802, 802T, 806 | POWER PLANT, TURBINE GENERATOR #3 ADDITION, SUBSTATION CONTROL HOUSE
B | 802A, 802B | POWER PLANT ADDITION, BAGHOUSE ADDITION
C | 801, 807 | REVERSE OSMOSIS BLDG, CHILLER HOUSE
D | 808 | WATER TREATMENT FACILITY
UNIVERSITY OF ALASKA FAIRBANKS
UTILITIES OPERATION
INSTITUTIONAL CONSERVATION PROGRAM
TECHNICAL ASSISTANCE STUDY
FOR UTILITIES OPERATION
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ELEV. = 445 FEET AND 3 INCHES BLDG.#802A
SCALE : 3/32"=1'
DATE : 05/18/90
AUTOCADD OPERATOR : MAXWELL J HOBSON
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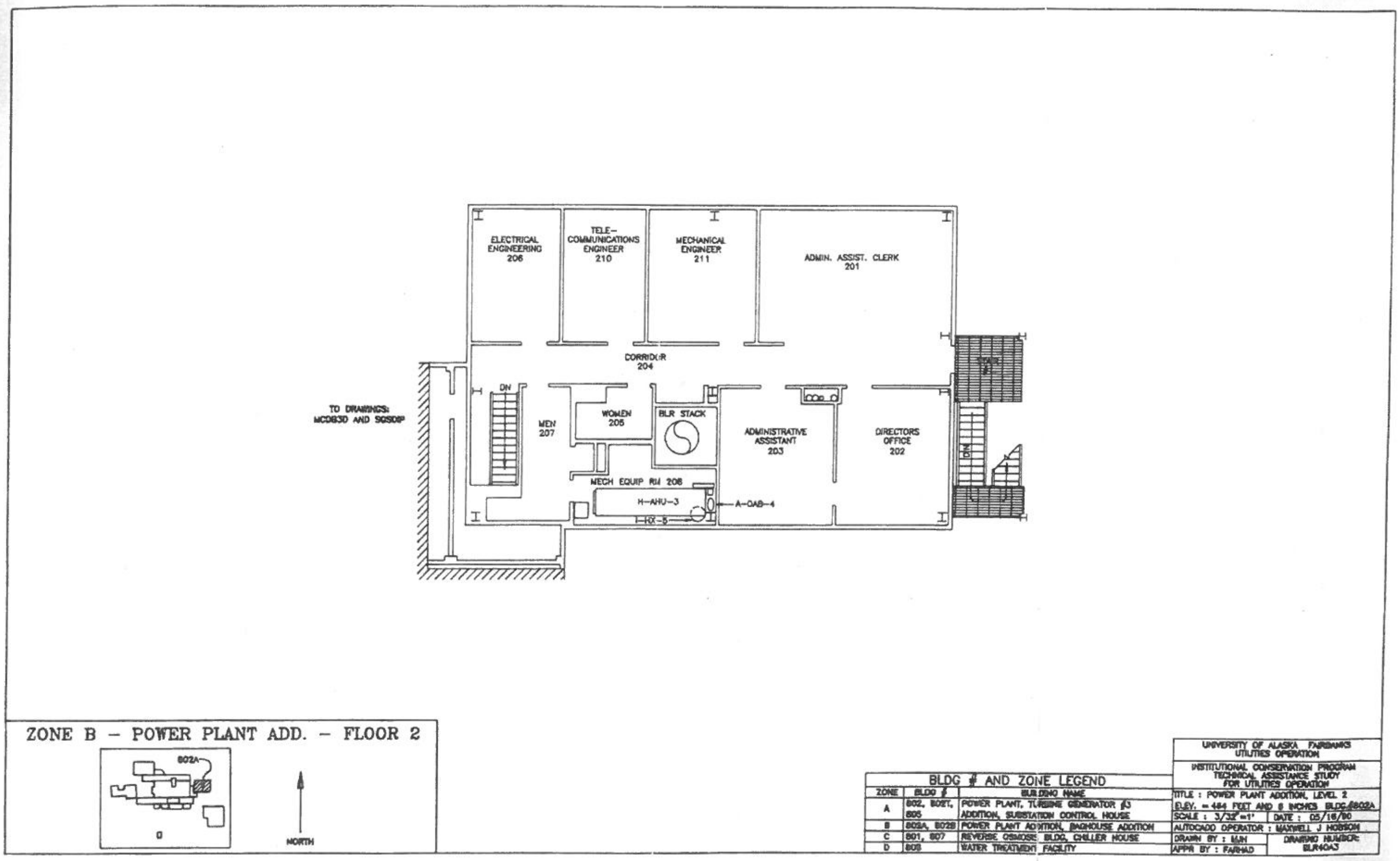
APPR BY : FARHAD
DRAWING NUMBER:
BLR4OA2


ELECTRICAL ENGINEERING 206
TELE-COMMUNICATIONS ENGINEER 210
MECHANICAL ENGINEER 211
ADMIN. ASSIST. CLERK 201
CORRIDOR 204
TO DRAWINGS: MCDB3D AND 5GSDP
DN
MEN 207
WOMEN 205
BLR STACK
ADMINISTRATIVE ASSISTANT 203
DIRECTORS OFFICE 202
MECH EQUIP RM 208
H-AHU-3
A-DAB-4
ZONE B – POWER PLANT ADD. – FLOOR 2
802A
NORTH
BLDG # AND ZONE LEGEND
ZONE
BLDG #
BUILDING NAME
A
802, 802T, 805
POWER PLANT, TURBINE GENERATOR #3 ADDITION, SUBSTATION CONTROL HOUSE
B
802A, 802B
POWER PLANT ADDITION, BAGHOUSE ADDITION
C
801, 807
REVERSE OSMOSIS BLDG, CHILLER HOUSE
D
808
WATER TREATMENT FACILITY
UNIVERSITY OF ALASKA FAIRBANKS UTILITIES OPERATION
INSTITUTIONAL CONSERVATION PROGRAM TECHNICAL ASSISTANCE STUDY FOR UTILITIES OPERATION
TITLE : POWER PLANT ADDITION, LEVEL 2
ELEV. = 484 FEET AND 8 INCHES BLDG.#802A
SCALE : 3/32"=1'
DATE : 05/16/90
AUTOCADD OPERATOR : MAXWELL J HOBSON
DRAWN BY : MJH
APPR BY : FARHAD
DRAWING NUMBER: BLR40A3

Julie Queen, Interim Vice Chancellor
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Administrative Services
P.O. Box 757900, Fairbanks, Alaska 99775-7500

April 23, 2019

Alice Edwards, Director
Division of Air Quality
Alaska Department of Environmental Conservation
PO Box 111800
Juneau, Alaska 99811

Transmitted digitally by email to: alice.edwards@alaska.gov
cc: cindy.heil@alaska.gov; deanna.huff@alaska.gov

RE: Fairbanks Serious $PM_{2.5}$ Nonattainment Area Best Available Control Technology (BACT) Determination – Economic Infeasibility of Sulfur Dioxide (SO_2) Emission Controls

Dear Ms. Edwards,

The University of Alaska Fairbanks (UAF) is providing additional information addressing certain aspects of the Alaska Department of Environmental Conservation (ADEC) BACT determinations associated with the Fairbanks Serious Nonattainment Area for particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 microns ($PM_{2.5}$) and requesting a determination of economic infeasibility of SO_2 emission controls. UAF understands that BACT determinations are a required component of the ADEC State Implementation Plan (SIP) submittal to address the $PM_{2.5}$ nonattainment area. UAF is concerned that a requirement to implement certain air pollutant emission controls will not be financially viable, particularly in light of existing state of Alaska budget issues. Specifically, UAF is addressing the ADEC preliminary BACT determination for SO_2 emission controls on emission unit (EU) 113, a predominantly coal-fired circulating fluidized bed (CFB) boiler. The maximum heat input capacity of EU 113 is 295.6 million British thermal units per hour (MMBtu/hr). EU 113 also has the capability to combust certain types of biomass (up to 20 or 25 percent of total heat input).

The ADEC preliminary BACT determination, dated March 22, 2018, presents the preliminary finding that BACT for SO_2 emissions from EU 113 would consist of the following requirements:

1) Control SO_2 emissions by operating and maintaining dry sorbent injection (DSI) and limestone injection at all times the unit is in operation.
2) The SO_2 emission rate shall not exceed 0.05 pounds per million British thermal unit (lb/MMBtu) averaged over a 3-hour period.
3) Burn low sulfur coal at all times that the dual fuel-fired boiler is combusting coal.
4) Demonstrate initial compliance with the SO_2 emission rate by conducting a performance test.

BACT is determined, in part, through a cost effectiveness analysis. ADEC prepared an analysis to determine the cost effectiveness of SO_2 controls deemed technically feasible for EU 113, including DSI. The ADEC analysis in Table 5-3 of the preliminary BACT determination presents a total capital cost of $4,394,193, total annualized costs of $2,246,238 per year, and a cost effectiveness of $7,536 per ton of SO_2 emissions removed. A capital recovery factor of 0.1098, calculated with 7 percent interest rate over a 15-year equipment life, was used to annualize costs. The cost effectiveness value is calculated by dividing the total annualized cost by the tons per year of air pollutant removed by the control device. In this case, DSI is estimated to remove up to 194 tons per year of SO_2. Contrary to the cost effectiveness figure of $7,538 per ton of SO_2 emissions removed presented in Table 5-3, the cost effectiveness for DSI based on the ADEC total annualized cost of $2,246,238 and the removal of 194 tons per year of SO_2 is actually $11,578 per ton of SO_2 emissions removed.

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g. At the sorbent injection rates that would be required to achieve the capture rates noted above, there is a potential for significant amounts of NO2 to be formed as a result of the chemical reaction which may form a brown plume and cause visual opacity issues[1].

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The preamble to the Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule dated August 24, 2016 includes guidance on preparing a Best Available Control Measures (BACM)/BACT determination in support of a serious $PM_{2.5}$ nonattainment area SIP. Specifically, determining whether an available control technology is economically feasible is addressed on page 58085 in volume 81 of the Federal Register. This section states

"…if a source contends that a source-specific control level should not be established because the source cannot afford the control measure or technology that is demonstrated to be economically feasible for purposes of BACM for other sources in its source category, the source should make its claim known to the state and support the claim with information regarding the impact of imposing the identified control measure or technology on the following financial indicators, to the extent applicable:

1. *Fixed and variable production costs ($/unit);*
2. *Product supply and demand elasticity;*
3. *Product prices (cost absorption vs. cost pass-through);*
4. *Expected costs incurred by competitors;*
5. *Company profits;*
6. *Employment costs;*
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Regardless of the exact cost, implementing DSI as SO_2 emissions controls on EU 113 is not financially possible for UAF. UAF is a public institution and an entity of the State of Alaska. On February 13, 2019 Governor Mike Dunleavy released his budget proposal for 2020. The University of Alaska (UA) is facing a proposed budget cut of $134 million, or 41 percent of the state's funding of $327 million, reducing the university's general fund support to $193 million. The cut is on top of state funding cuts that have occurred for four out of the last five years, resulting in program reductions and the loss of more than 1,200 faculty and staff. Under the Governor's spending plan, if his proposed cut is sustained by the legislature, it would be the largest year-over-year reduction in the university's history and would take UA back to 2002 funding levels. These cuts substantially impact UA and harm Alaska's ability to grow the highly trained workforce necessary to be economically competitive with other states.

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steam, which both heats and cools campus and spins turbines to create electricity. Instead of purchasing electricity from the distribution grid and burning fuel in our on-site boilers to produce heat, UAF can use combined heat and power to provide both products as part of one combustion process.

If DSI were to be imposed as BACT for SO_2 emissions on EU 113, the expected impacts to the UAF financial indicators are as follows: (All costs from the 2017 UAF BACT Analysis adjusted for inflation from 2016 to 2019 dollars[2])

Capital Cost
UAF estimated in the January 2017 BACT analysis a total capital cost to install DSI control technology at EU ID 113 of $2,687,100.

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EU 113 is in the commissioning phase and has not yet operated at the maximum design production rate at steady state that would allow meaningful fixed and variable production cost ratios ($/kW or $/klb steam) to be calculated.

Cost Contributor	Annualized Cost
Production costs ($/kW or $/1,000 lb steam) *without* DSI	Not known
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Labor for handling limestone and additional ash	$15,500[6]
Potentially voiding construction warranties	Not known

While the actual production costs of the new EU 113 boiler are not yet known, the following are the 2019 operating costs for the current UAF power plant[7]:

Operation	Cost
Electric	$0.203 per kilowatt hour
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Company profits is not an applicable parameter because UAF is a State of Alaska facility, not a for-profit company.

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UAF has requested and has not yet been provided the ADEC calculations for the economic analysis of SO_2 controls as discussed above.

<u>Other costs (e.g. for BACM implemented by public sector entities)</u>
UAF is a state institution with a budget that is determined by the Legislature. Spending funding on the DSI would cause funds to be diverted from the educational and research mission of the University. Impacts from the lack of funds include fewer staff to provide support services (grounds, maintenance, transportation, human resources, payroll, risk management, safety, fire and police, procurement), reduction in degree programs, further deferred maintenance which will cause deteriation of facilities and roads, inability to replace defunct equipment, and other impacts. The cost in dollars would be the amount of money that would be diverted for operations and maintenance of the DSI annually, plus the cost of construction of the plant and the interest payable on any bonds – the annualized cost of $2,246,238.

<u>Other factors</u>
It is unlikely that the incremental reduction of SO_2 emissions from EU ID 113 with the DSI system installed (compared to air quality permit limits) would significantly reduce $PM_{2.5}$ concentrations in the FNSB serious nonattainment area because:

- The stack height of EU 113 is 210 feet.
- The UAF CHPP is located towards the west end of Fairbanks of the serious nonattainment area. Flow through the airshed is comparable to flow through the local watershed (roughly east to west), therefore with normal conditions in place, impacts to the non-attainment area should be minimal.

DSI technology requires the addition of limestone, lime, or sodium bicarbonate to the boiler flue gas post-combustion prior to the baghouse. Any unreacted sorbent could alter the physical properties of the coal ash, including the leachability of metals. With an estimated quantity of 1314 tons per year of sorbent used in the DSI process at UAF, the amount of waste material captured in the baghouse will increase significantly. UAF could face the added significant cost of disposal of an increased volume of coal ash with increased hazardous properties if UAF is compelled to install DSI technology at EU 113.

UAF will commit to use of ULSD on its existing permitted fuel burning equipment that is not currently required to use this type of fuel, but understands that this will be a requirements in the serious SIP. However, any additional pollution control equipment added to any of our units will be an additional hardship to the University and its mission. Please consider this request for economic and technological infeasibility of installation of additional pollution control equipment on our permitted units. UAF will commit to completing additional source testing for SO_2 to substantiate the reduction in sulfur due to elimination of the existing coal-fired boilers and the use of the new circulated fluidized bed boiler. UAF will complete additional SO_2 source testing within 6 months after initial start-up.[8] Also, once the facility is operational, EU IDs 3 and 4 will reduce their usage dramatically which will also lower the sulfur emissions from UAF.

If you have any questions, please contact Russ Steiger at 907-474-5812 or rhsteiger@alaska.edu or Frances Isgrigg at 907-474-5487 or fisgrigg@alaska.edu.

Sincerely,

Julie Queen
Interim Vice Chancellor for Administrative Services
University of Alaska Fairbanks

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Although not explicitly stated in the definition, startup excludes firing an emissions unit for the purpose of commissioning prior to the emissions unit becoming operational. Pre-startup and startup are discussed in the 1979 EPA Instruction Manual for Clarification of Startup in Source Categories Affected by New Source Performance Standards.

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UNIVERSITY OF ALASKA FAIRBANKS
Administrative Services
P.O. Box 757900, Fairbanks, Alaska 99775-7500

April 23, 2019

Alice Edwards, Director
Division of Air Quality
Alaska Department of Environmental Conservation
PO Box 111800
Juneau, Alaska 99811

Transmitted digitally by email to: alice.edwards@alaska.gov
cc: cindy.heil@alaska.gov; deanna.huff@alaska.gov

RE: Fairbanks Serious $PM_{2.5}$ Nonattainment Area Best Available Control Technology (BACT) Determination – Economic Infeasibility of Sulfur Dioxide (SO_2) Emission Controls

Dear Ms. Edwards,

The University of Alaska Fairbanks (UAF) is providing additional information addressing certain aspects of the Alaska Department of Environmental Conservation (ADEC) BACT determinations associated with the Fairbanks Serious Nonattainment Area for particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 microns ($PM_{2.5}$) and requesting a determination of economic infeasibility of SO_2 emission controls. UAF understands that BACT determinations are a required component of the ADEC State Implementation Plan (SIP) submittal to address the $PM_{2.5}$ nonattainment area. UAF is concerned that a requirement to implement certain air pollutant emission controls will not be financially viable, particularly in light of existing state of Alaska budget issues. Specifically, UAF is addressing the ADEC preliminary BACT determination for SO_2 emission controls on emission unit (EU) 113, a predominantly coal-fired circulating fluidized bed (CFB) boiler. The maximum heat input capacity of EU 113 is 295.6 million British thermal units per hour (MMBtu/hr). EU 113 also has the capability to combust certain types of biomass (up to 20 or 25 percent of total heat input).

The ADEC preliminary BACT determination, dated March 22, 2018, presents the preliminary finding that BACT for SO_2 emissions from EU 113 would consist of the following requirements:

1) Control SO_2 emissions by operating and maintaining dry sorbent injection (DSI) and limestone injection at all times the unit is in operation.
2) The SO_2 emission rate shall not exceed 0.05 pounds per million British thermal unit (lb/MMBtu) averaged over a 3-hour period.
3) Burn low sulfur coal at all times that the dual fuel-fired boiler is combusting coal.
4) Demonstrate initial compliance with the SO_2 emission rate by conducting a performance test.

BACT is determined, in part, through a cost effectiveness analysis. ADEC prepared an analysis to determine the cost effectiveness of SO_2 controls deemed technically feasible for EU 113, including DSI. The ADEC analysis in Table 5-3 of the preliminary BACT determination presents a total capital cost of $4,394,193, total annualized costs of $2,246,238 per year, and a cost effectiveness of $7,536 per ton of SO_2 emissions removed. A capital recovery factor of 0.1098, calculated with 7 percent interest rate over a 15-year equipment life, was used to annualize costs. The cost effectiveness value is calculated by dividing the total annualized cost by the tons per year of air pollutant removed by the control device. In this case, DSI is estimated to remove up to 194 tons per year of SO_2. Contrary to the cost effectiveness figure of $7,538 per ton of SO_2 emissions removed presented in Table 5-3, the cost effectiveness for DSI based on the ADEC total annualized cost of $2,246,238 and the removal of 194 tons per year of SO_2 is actually $11,578 per ton of SO_2 emissions removed.

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