2011 Updated Facility Design Prevention of Significant Deterioration Air Quality Construction Permit Application Source ID No. 1890231

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Prepared For

Abengoa Bioenergy Biomass of Kansas, LLC
Hugoton, Kansas

WLA Project No. 165-009

May 2011

Revision No. 0

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Prepared for:

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WLA Project No. 165-009

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Air Quality Construction Permit Application
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1) EPA's RACT/BACT/LAER Clearinghouse (RBLC) Search Results for Process Type 11.000 – *Utility and Large Industrial Size Boilers/Furnaces (>250 MMBtu/hr),* Subcategory Type 11.120 – Biomass.
2) Detailed Costs Analysis of Selective Catalytic Reduction Control for the Biomass-Fired Stoker Boiler.
3) Detailed Costs Analysis of Selective Non-Catalytic Reduction Control for the Biomass-Fired Stoker Boiler.

References

Air Pollution Control Cost Manual, Sixth Edition, Section 4 – NOx Controls, U.S. Environmental Protection Agency, EPA-452/B-02-001, July 2002 (Selective Non-Catalytic Reduction) and March 2003 (Selective Catalytic Reduction).

Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources (AP-42), Fifth Edition, U.S. Environmental Protection Agency.

Fugitive Dust Background Document and Technical Information Document for Best Available Control Measures, U.S. Environmental Protection Agency, EPA-450/2-92-004, September 1992.

RACT/BACT/LAER Clearinghouse Website, http://cfpub.epa.gov/rblc, U.S. Environmental Protection Agency.

Section 1.0
PSD Air Quality Construction Permit Application Summary

1.1 Current Proposed Project

Abengoa Bioenergy Biomass of Kansas, LLC (ABBK) intends to build and operate a biomass-to-ethanol and biomass-to-energy production facility. The proposed facility will employ two different biomass processes to produce fuel ethanol, lignin-rich stillage and stillage syrup, soil amendment ash, and power. These two processes include the following:

- Biomass-to-Ethanol: Enzymatic Hydrolysis Ethanol Production Process (EH Plant), 30 Million Gallon Per Year Anhydrous Ethanol Capacity; and
- Biomass-to-Power: Cogeneration Process (CoGen Plant), 22 Megawatt Capacity.

1.2 Permitting History

A PSD air quality construction permit application was originally submitted to the Kansas Department of Health and Environment (KDHE) in July 2008. The very nature of "first-of-its-kind" cellulosic ethanol technology, and turbulent economic conditions, contributed to project scope and design changes that resulted in revisions to the application several times since the July 2008 submission. A 2011 redesign of the project was required to satisfy U.S. Department of Energy (DOE) partnership criteria and the February 21, 2011 National Emission Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters standards.

1.3 Regulated Project Emissions

The proposed facility will generate emissions of several regulated air pollutants, including particulate matter (PM; a.k.a. total suspendable particulate (TSP), generally defined as PM_{30}), particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM_{10}), particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$), nitrogen oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), volatile organic compounds (VOC), hazardous air pollutants (HAPs), and greenhouse gases (GHGs).

The KDHE continues to categorize the proposed facility as a "chemical process plant", one of the 27 "Federally designated fugitive emissions sources" (i.e. source categories). As defined in Kansas Administrative Regulations Chapter 28, Title 19, Section 200(kk)(3)

(K.A.R. 28-19-200(kk)(3)), a major source shall include a major stationary source of air pollutants that *"directly emits or has the potential-to-emit 100 tons per year or more of any air pollutant, including any major source of fugitive emissions of any such pollutant from a Federally designated fugitive emissions source"*. Therefore, the 100 tons per year (ton/yr) major stationary source threshold for criteria pollutants applies to the EH Plant.

According to K.A.R. 28-19-17, *Prevention of Significant Deterioration*, K.A.R. 28-19-200, *General Provisions; Definitions*, and K.A.R. 28-19-300, *Construction Permits and Approvals; Applicability*, the proposed facility is required to obtain a PSD air quality construction permit due to the following:

- The potential to emit (PTE) for the proposed facility equals or exceeds either 25 ton/yr of particulate matter (PM) or 15 ton/yr of PM_{10}; 40 ton/yr of sulfur dioxide (SO_2) or sulfur trioxide (SO_3) or a combination thereof; 100 ton/yr of carbon monoxide (CO); 40 ton/yr of volatile organic compounds (VOC); and 40 ton/yr of oxides of nitrogen (NOx);
- The facility belongs to the following source categories:
    1) Chemical process plant with a Standard Industrial Code (SIC) 2869; and
    2) Fossil fuel boilers totaling more than 250,000,000 Btu/hr with a SIC 4911.
- The facility is a major source of the criteria pollutants: PM/PM_{10}, SO_2, CO, and NOx.

The proposed facility will be a sythetic minor source for HAPs under K.A.R. 28-19-750, *Hazardous Air Pollutants; Maximum Achievable Control Technology*. Emissions will be controlled to below the major source thresholds defined in Title 40, Code of Federal Regulations, Part 63, Section 63.2 (40 CFR §63.2), *"Major source means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants"*. The control of emissions will be through the implementation of either Maximum Achievable Control Technology (MACT) or Generally Available Control Technology (GACT) that will be federally enforceable on all HAP emitting sources. The MACT/GACT analysis will detail the control technologies proposed and the methods that will be used to demonstrate compliance.

Table 1-1 summarizes the maximum PTE for the proposed facility.

Table 1–1
Summary of Emissions for Abengoa Bioenergy Biomass of Kansas, LLC

Pollutant	Uncontrolled Facility-Wide Emissions (ton/yr)	Controlled Facility-Wide Emissions (ton/yr)	PSD Significant Emission Rate (ton/yr)	PSD Review Required
PM	18,044.6	130.5	25	Yes
PM_{10}	16,070.5	118.6	15	Yes
$PM_{2.5}$	13,560.9	81.2	15	No
NO_x	1,665.8	916.5	40	Yes
SO_2	5,830.5	483.4	40	Yes
H_2SO_4 (SAM)	355.79	3.56	7	No
CO	519.5	519.5	100	Yes
VOC	1,242.5	29.0	40	No
Lead	0.11	0.11	0.6	No
Hydrogen Fluoride (HF)	0.66	0.01	3	No
Single HAP (HCl)	569.5	5.7	N/A	No
Total HAPs	615.7	20.1	N/A	No
CO_2e	590,299	590,299	N/A	No

Because the proposed facility meets the current K.A.R. definition for major source for criteria pollutants, K.A.R. 28-19-350, *Prevention of Significant Deterioration of Air Quality*, is applicable. The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the National Ambient Air Quality Standards (NAAQS), while providing a margin for future industrial and commercial growth. The primary provisions of PSD regulations require that new major stationary sources, like the proposed facility, be reviewed prior to construction to ensure compliance with the applicable NAAQS and PSD increments, as well as apply BACT to minimize the emissions of air pollutants. Additional impacts analyses are also required under 40 CFR §52.21(o), and must describe air quality and related impacts due to associated growth and construction, as well as potential impacts of atmospheric emissions on soils, vegetation and visibility impairment.

1.4 Report Organization

This report is a technical support document for the PSD air quality construction permit application. This report contains a revised BACT analysis, MACT analysisand other federal reguatlions review that were not previously addressed in the 2011 updated facility design PSD air quality construction permit application.

This report has been organized such that each required PSD construction permit application component is provided in a section of this report. A summary of the contents of each section of this report are provided herein.

1.4.1 Sections

1.4.1.1 *Section 2.0: Best Available Control Technology Analysis*

Under the PSD program, newly constructed and modified major sources in attainment areas, must implement BACT. The proposed facility is located in an area designated as an attainment or unclassified area, as defined in 40 CFR §52.21. A detailed BACT analysis for each individual new affected emission unit and pollutant emitting activity with a significant emissions increase was performed and is presented in Section 2.0. The determination of the final BACT is made by KDHE, and is federally enforceable.

1.4.1.2 *Section 3.0: Maximum Achievable Control Technology Analysis*

The national emission standards for hazardous air pollutants (NESHAPs) apply to both major sources in specifically regulated industrial source categories and area sources of certain types of emissions. The proposed facility is subject to certain NESHAPs listed in 40 CFR Part 63 and will voluntarily comply with other NESHAPs requirements to reduce facility-wide HAP emissions below major source thresholds. A detailed NESHAPs applicability review and MACT/GACT analysis for each new affected emission unit and pollutant emitting activity will be performed and is presented in Section 3.0. The MACT standards set forth in applicable NESHAPs are federally enforceable as are the emission reductions to below major source thresholds.

1.4.1.3 *Section 4.0: Code of Federal Regulations not specifically addressed in the Kansas Administrative Regulations*

The Federal Clean Air Act (CAA) and CAA Amendments set forth regulatory requirements for air emission sources. These regulations are set forth under 40 CFR and administered by the U.S. Environmental Protection Agency (EPA) or delegated authority. For the most part, Kansas has adopted regulations to implement the federal air quality regulations in its

state implementation plan, and has received federal approval for those regulations. This section reviews potentially applicable requirements in the Code of Federal Regulations not specifically addressed in the Kansas Administrative Regulations (K.A.R.).

Section 2.0
Best Available Control Technology Analysis

2.1 Best Available Control Technology Requirements

As described in Section 1.0, the proposed facility is subject to PSD review as a new major source of criteria pollutants. Each emission unit that emits a criteria pollutant, for which the project is major, is required to apply BACT for that pollutant. In no event can the application of BACT result in the emission of any pollutant that would exceed the emissions allowed by an applicable New Source Performance Standard (NSPS). A summary of the units subject to BACT and the unit's BACT requirements for the units are presented in Table 2-1. This section is organized by emission unit and then pollutant. When appropriate, emission units with similar characteristics and BACT applicability are grouped together.

Table 2–1
Summary of Emission Units and Pollutants Subject to BACT and PSD-BACT Limits

Stack ID	Equipment/Process	Pollutant	Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-11120	Floor Sweep System DC	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.0007 gr/dscf	
EP-11110	Bale Grinder DC	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.0007 gr/dscf	
EP-11170	Classifier Cyclone # 1 DC	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.0007 gr/dscf	
EP-11270	Classifier Cyclone # 2 DC	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.0007 gr/dscf	
EP-11711	Boiler Feed System DC	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.0007 gr/dscf	
EP-20514	Boiler Bottoms Ash Handling DC #1	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.002 gr/dscf	
EP-20510	Boiler Fly Ash Handling DC #1	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.002 gr/dscf	
EP-20520	Boiler Fly Ash Handling DC #2	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.002 gr/dscf	
EP-20512	Lime Handling DC #1	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.002 gr/dscf	
EP-11110FUG	Crop Grinding and Conveying	$PM/PM_{10}/PM_{2.5}$	None	Total Enclosure Utilizing Fabric Filter Baghouses
EP-11110FUG	Crop Residues and Energy Crops Receiving Via Truck	$PM/PM_{10}/PM_{2.5}$	See Area 11000	Good Work Practices
EP-02710	Bulk Fly Ash Load-Out Silo	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.002 gr/dscf	
EP-02711	Bulk Fly Ash Load-Out Silo Spout	PM/PM_{10}	0.004 gr/dscf	Fabric Filter Baghouse
		$PM_{2.5}$	0.002 gr/dscf	

Table 2–1
Summary of Emission Units and Pollutants Subject to BACT and PSD-BACT Limits

Stack ID	Equipment/Process	Pollutant	Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-18185	EH Fermentation CO_2 Scrubber	Condensable PM	0.1 lb/hr	Wet Scrubber
		NO_2	0.08 lb/hr	Wet Scrubber
N/A	EH Distillation Vent Scrubber (S-18180)	Ducted to EH Fermentation CO_2 Scrubber, EP-18185 for additional control. See EP-18185.		
EP-20001	Biomass-Fired Boiler	Condensable PM	0.017 lb/MMBtu	SDA with Fabric Filter Baghouse
		Filterable PM	0.015 lb/MMBtu	Fabric Filter Baghouse
		Filterable PM_{10}	0.013 lb/MMBtu	Fabric Filter Baghouse
		Filterable $PM_{2.5}$	0.011 lb/MMBtu	Fabric Filter Baghouse
		NOx (Including Start-up/Shutdown)	0.415 lb/MMBtu (30-day rolling)	SNCR with Good Combustion Practices
		NOx (Including Start-up/Shutdown)	207.6 lb/hr (maximum 1-hour)	SNCR with Good Combustion Practices
		SO_2 (Including Start-up/Shutdown)	0.21 lb/MMBtu (30-day rolling) [OR] 92% Control	Spray Dry Absorber
		SO_2 (Including Start-up/Shutdown)	106.2 lb/hr (maximum 1-hour)	Spray Dry Absorber
		CO	260 ppmv@3%O_2	Good Combustion Practices
EP-04001	Cooling Water Tower	$PM/PM_{10}/PM_{2.5}$	1,575 ppm TDS	Drift Eliminator with 0.0005% Drift Rate
EP-09001	Flare	$PM/PM_{10}/PM_{2.5}$	None	Smokeless Design
		NOx	0.33 lb/hr 0.12 ton/yr	Low NOx Burner
		SO_2	≤ 100 ppm Sulfur by Weight	Treated Biogas and Pipeline Grade Natural Gas Only
		CO	1.76 lb/hr 0.48 ton/yr	Good Combustion Practices
EP-06001 (EMG)	Firewater Pump Engine	$PM/PM_{10}/PM_{2.5}$	0.08 g/Hp-hr	EPA Tier 3 Standard
		NOx	2.57 g/Hp-hr	EPA Tier 3 Standard
		SO_2	≤ 0.0015% Sulfur by Weight	Ultra Low Sulfur Distillate Oil
		CO	0.67 g/Hp-hr	EPA Tier 3 Standard
EP-01000	Paved Haul Roads	$PM/PM_{10}/PM_{2.5}$	148 Trucks per Day 7-Day Rolling Average	Truck traffic fugitive control strategy and monitoring plan, including sweeping and speed limits

Table 2–1
Summary of Emission Units and Pollutants Subject to BACT and PSD-BACT Limits

Stack ID	Equipment/Process	Pollutant	Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-01050	Biomass Laydown Roads	$PM/PM_{10}/PM_{2.5}$	109 Trucks per Day 7-Day Rolling Average	Truck traffic fugitive control strategy and monitoring plan, including sweeping and speed limits

2.2 BACT Methodology

BACT is an emissions limitation based on the maximum degree of reduction that is achievable for each pollutant subject to regulation under the CAA which would be emitted from any major emitting facility, on a case-by-case basis, taking into account technical feasibility, energy, environmental, and economic impacts.

The "top-down" BACT evaluation process requires that all technically feasible control technologies be ranked in descending order of control efficiencies. The most effective technology is selected as BACT unless the applicant demonstrates that energy, environmental and/or economic impacts justify a conclusion that the most effective technology is not "achievable". In this case, the next most effective technology is analyzed until the top performing "achievable" technology is identified.

The BACT analyses presented in this application conform to the EPA guidelines. The five steps of the "top-down" BACT evaluation procedure are as follows:

Step 1. Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation.

Step 2. Eliminate technically infeasible or unavailable technology options. A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

Step 3. Rank remaining control technologies in order of decreasing effectiveness. This includes:

- control effectiveness (percent pollutant removed);
- expected emission reduction (ton/yr);
- energy impacts (Btu, kW-hr);
- environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
- economic impacts (total cost effectiveness and incremental cost effectiveness).

Step 4. Evaluate most effective controls and document results. A case-by-case evaluation of energy, environmental, and economic impacts is performed for each remaining control technology.

Step 5. Select the most effective control that has acceptable energy, environmental, and economic impacts.

The most stringent control technology for similar or identical emission units previously approved should be identified during the BACT process. The Lowest Achievable Emission Rate (LAER) is the most stringent limit or standard of performance that is achievable by a class or category of emission sources. LAER analyses do not typically consider economic impacts and except when the cost of the associated level of control is so great that the project could not be built. If a source elects to install equipment to meet LAER, no further analysis is required.

There have been multiple assessments performed and documented at EPA's **R**ACT/**B**ACT/**L**AER **C**learinghouse (RBLC) which can help in the BACT process. EPA's RBLC database contains information pertaining to PSD air permits issued in the United States. If the proposed BACT is the most stringent control technology, as obtained from the EPA's RBLC database, no further analysis is required; however, if the facility decides to use a different control technology, additional analysis is required.

During the BACT analysis, control technologies are evaluated to determine their technical feasibility. Technical feasibility is established through physical, chemical or other engineering principles for each control option. The facility must demonstrate whether or not technical difficulties would preclude the successful use of a potentially applicable control option. The economic impact of a control alternative is evaluated by considering

the cost effectiveness (dollars per ton of pollutant removed) for each option. The analysis includes an estimate of the capital and annualized costs for each alternative based on vendor quotes and established EPA cost estimating procedures. If a control technology is technically and economically feasible and provides the most stringent emission level, that control is considered BACT unless energy or environmental impacts preclude its use. The energy impact analysis estimates the direct energy impacts of the control alternatives in units of energy consumption. The environmental impact associated with a control alternative can be considered if a dispersion modeling analysis is performed.

The BACT determination for a project, in terms of emission control level, is made utilizing comparisons to similar projects for the appropriate emission level. However, BACT for a proposed project is not necessarily the lowest emission limit recently established for another somewhat similar project. Where a control technology has been successfully applied to similar sources in a source category, an applicant should document significant cost differences, if any, between the application of the control technology on those other sources and the particular source under review. The determination of the final BACT is made by the state regulatory agency (Kansas Department of Health and Environment, KDHE) and is federally enforceable.

2.3 Fugitive Operations Associated with Biomass Receiving and Processing BACT Analysis

2.3.1 Source Emissions

Agricultural residues and energy crops will be delivered in bale form primarily on flatbed / module / custom trucks. The baled biomass will either be unloaded directly onto conveyors supplying the grinding lines or unloaded at the biomass overnight staging area or biomass storage field. The biomass overnight staging area and biomass storage field are constantly active as bales are brought onsite and stored as well as retrieved for use in the process during the night shift or during delivery disruptions. Handling operations will consist of receiving the biomass bales by truck and unloading them at bale receiving conveyors to support a "nearly just in time" operational process.

The particulate emissions generated from the unloading of material from the trucks and the loading of the material into roll-off dumpsters were assumed

equivalent to the particulate emissions generated by the drop operation for aggregate handling and storage piles, as calculated in AP-42, Section 13.2.1, *Aggregate Handling and Storage Piles*, November 2006. The bound agricultural residues and energy crops will typically not be a source of suspended $PM/PM_{10}/PM_{2.5}$ emissions until grinded; however, for the purposes of the receiving PTE calculations, worst-case fugitive emissions were estimated using AP-42 Section 13.2.1.

2.3.2 $PM/PM_{10}/PM_{2.5}$ BACT Review

2.3.2.1 Identify Available Control Options

The following control options have been identified and considered in determining BACT:

- Total or partial enclosed buildings, conveyors, or silos/surge bins without dust collection systems; and
- Total enclosures with dust collection systems which collect and control particulate emissions with the use of:
  - Fabric Filter Baghouse;
  - Wet Electrostatic Precipitators (ESPs);
  - Dry ESPs;
  - Venturi Scrubbers; or
  - Cyclones.

2.3.2.2 Eliminate Technically Infeasible Control Options

Enclosures reduce particulate emissions by containing the material and preventing release of particulates or by reducing the wind that can entrain small exposed particles. Enclosures are typically used to capture emissions from operations like truck unloading so that the dust emitted can be collected and vented to a control device.

The effectiveness of the enclosure is directly impacted by the degree to which the operation is enclosed. Totally enclosed buildings offer the highest degree of control. Partial enclosures, such as those used for rail car and truck unloading, are less effective due to the openings required for the rail car and truck passage. The effectiveness of these types of

enclosures can be increased through the use of doors or flexible curtains, where feasible.

Due to health and safety reasons, most enclosed operations require ventilation to remove the particulates generated by the operations. Although there are numerous devices that are effective at removing particulates from air streams, the most common and effective vent control for enclosures is the fabric filter baghouse. A baghouse has been established by the industry as the most effective control device for removing particulates from ventilation and conveying air.

Other control devices, such as ESPs, induce an electric field between oppositely charged plates where charged particulates are removed from the exhaust stream. The use of a dry ESP with the suspended particulates is a safety hazard as the particulate dust may explode if exposed to an ignition source such as spark between the charged ESP plates. Wet ESPs, Venturi scrubbers and cyclones are considered technically feasible for use in the receiving operations.

2.3.2.3 Rank Technically Feasible Control Options

Control Technology	Reduction Efficiency
Partial or Total Enclosure	50% to 99+%
Baghouse	99+%
Wet ESP	99+%
Venturi Scrubber	70% to 99+%
Cyclone	≤90%

The reduction in emissions from the decrease in wind velocity due to an enclosure is expected to be up to 100% when compared to processes in the open. A baghouse, wet ESP and Venturi scrubber are all capable of achieving additional emissions reductions of 99% or more. However, based on previous performance and application experience, a baghouse is more likely to achieve and maintain 99+% efficiency; and a wet ESP or Venturi scrubber offer no performance or cost advantages. Two disadvantages of a Venturi scrubber are the requirement for water and disposal of a wet waste.

Total enclosure of an emission unit coupled with a dust collection/ventilation system vented to a fabric filter baghouse is the most stringent control technology.

2.3.2.4 *Evaluate Technically Feasible Control Option*

EPA's RBLC database was reviewed to identify particulate control technologies that were potentially applicable to the biomass receiving operations. There were no emission units identified in the RBLC database that were similar to the agricultural residues and energy crops receiving operations.

This BACT analysis will first review the cost effectiveness of total and partial enclosure of the receiving area. If partial or total enclosure of the receiving areas is determined to be economically viable, the coupling of the enclosures with a dust collection/ventilation system will then be evaluated.

Estimated emissions from biomass receiving operations are summarized in Table 2-2 along with the resulting emissions when controlled by the technically feasible control technologies.

Table 2–2
Biomass Receiving Operations PM/PM_{10} Uncontrolled and BACT Emission Rates

Emission Point No.	Emission Source	Baseline (0% Control Efficiency) (ton/yr)	Total Enclosure (99% Control Efficiency) (ton/yr)	Partial Enclosure (50% Control Efficiency) (ton/yr)	Emission Reductions (ton/yr)
EP-11110FUG	Crop Residues Receiving via Truck	PM: 0.16 PM_{10}: 0.075	0.00	PM: 0.08 PM_{10}: 0.037	PM: 0.08 to 0.16 PM_{10}: 0.037 to 0.075

Energy Impacts

Use of an enclosure will result in additional electricity required for ventilation.

Environmental Impacts

There are no negative environmental impacts associated with the construction of an enclosure, except for the consumption of building materials that otherwise would not be used.

Economic Impacts

Table 2-3 presents the capital and annual costs associated with the construction of an enclosure for the agricultural residues and energy crops receiving system (EP-11110FUG). Preliminary capital costs were provided by ABBK. Annual costs were estimated using standard engineering estimating practices presented in Section 2, *Generic Equipment and Devices,* of the EPA Air Pollution Control Cost Manual, Sixth Edition, EPA-425/B-02-001.

Table 2–3
Agricultural Residues and Energy Crops Receiving Operations
Capital and Annual Cost Summary

Description of Cost	Cost in US Dollars[1]	Comments	Notes
TOTAL CAPITAL INVESTMENT (TCI)	**$700,000**		Note 2
ANNUAL INDIRECT COSTS (IC)			
Administrative Charges	$14,000	2% of TCI	Note 3
Property Taxes	$7,000	1% of TCI	Note 3
Insurance	$7,000	1% of TCI	Note 3
Capital Recovery	$56,400	CRF x TCI	Note 5
TOTAL ANNUAL IC	$84,400		
ANNUALIZED COSTS FOR TOTAL ENCLOSURE	**$84,400**		
ANNUALIZED COSTS FOR PARTIAL ENCLOSURE	**$56,300**		Note 6

Note 1: Rounded to nearest $100.
Note 2: Capital costs provided by ABBK
Note 3: Annual operating costs are minimal and consist of minor expenses such as painting and architectural repairs, as well as the cost of operating the enclosure's ventilation system. These direct costs have not been included in the cost analysis of the enclosure.
Note 4: Overhead is not considered because it is based on the sum of operating, supervisory, and maintenance labor and material costs, which are assumed negligible for the enclosure.
Note 5: The capital recovery cost factor (CRF) is a function of the building life (typically 30 years) and the opportunity cost of the capital (i.e., interest rate). The capital recovery factor is calculated as follows:

$$CRF = [\, i\,(1 + i)^n \,] / [(1 + i)^n - 1]$$

Where: CRF = capital recovery factor
i = annual interest rate (fraction)
n = number of payment years

A 30-year equipment life and a 7% interest rate CRF = 0.0806.
Note 6: Partial enclosure costs estimated to be $^2/_3$ total enclosure costs.

Table 2-4 summarizes the PM/PM_{10} BACT analysis results for agricultural residues and energy crops receiving (EP-11110FUG). The baseline

emission rates used for calculating costs are based on no controls. The table shows that additional PM/PM_{10} reductions could be provided by the use of an enclosure for each system. The annualized cost for an enclosure is calculated as the sum of the annual costs, plus a capital recovery factor multiplied by the total capital investment costs. The total annualized cost to achieve either 50% or 99% control of the PM/PM_{10} from the agricultural residues and energy crops receiving system is estimated to be $56,300 or $84,400, respectively.

Table 2–4
Agricultural Residues and Energy Crops Receiving Operations
PM/PM_{10} BACT Analysis Results

Control Option	Emission Reduction (ton/yr)[1]	Annualized Costs ($/yr)	Cost Effectiveness ($/ton)	Energy Impacts[2]	Environmental Impacts[3]
None	N/A	Baseline	N/A	Baseline	Baseline
Total Enclosure	PM: 0.16 PM_{10}: 0.075	$84,400	PM: $0.53MM PM_{10}: $1.13MM	Negligible	Negligible
Partial Enclosure	PM: 0.08 PM_{10}: 0.037	$56,300	PM: $0.70MM PM_{10}: $1.52MM	Negligible	Negligible

Note 1: PM emissions reductions estimated using a baseline PM emission rate of 0.16 ton/yr and 99% control efficiency for total enclosure, or 50% control efficiency for partial enclosure. PM_{10} emissions reductions estimated using a baseline PM_{10} emission rate of 0.075 ton/yr and 99% control efficiency for total enclosure, or 50% control efficiency for partial enclosure.
Note 2: Energy impacts were assumed negligible; however, electricity will be required to operate the ventilation and baghouse systems, if installed.
Note 3: Environmental impacts were assumed negligible; however, building materials will be required for the construction of the enclosure.

Based on the lowest cost effectiveness of over $0.53MM per ton of PM removed and over $1.13MM per ton of PM_{10} removed, the PM/PM_{10} reductions for emissions from Crop Residues Receiving via Truck (EP-11110FUG) come at a substantial cost in terms of economic impacts. Therefore, ABBK concludes that the PM/PM_{10} emissions reductions that could be attained with enclosures for agricultural residues and energy crops receiving are not justified by the cost of control associated with this technology.

2.3.2.5 *Establish BACT*

The use of an enclosure is technically feasible for Crop Residues Receiving via Truck (EP-11110FUG); however, it is not cost-effective to control

fugitive dust using an enclosure or other add-on control device. The proposed BACT is good work practices with no additional controls.

2.3.2.6 *BACT Compliance*

A Fugitive Dust Control Plan will be developed and will detail the work practices to be implemented to reduce fugitive emissions from agricultural residues and energy crops receiving and processing operations. Further, opacity from this source is limited to 20% by K.A.R. 28-19-650. The Fugitive Dust Control Plan will address this source to ensure compliance with the K.A.R. standard. ABBK will also provide a copy of the Fugitive Dust Control Plan and associated documentation to KDHE upon request to demonstrate compliance with BACT.

2.4 Agricultural Residues and Energy Crops Grinding/Hammermilling, Handling and Storage Operations BACT Analysis

2.4.1 Source Emissions

The agricultural residues and energy crops grinding/hammermilling, handling and storage operations are described in detail in Section 2.1 of the 2011 updated PSD air quality construction permit application. The agricultural residues and energy crops grinding/hammermilling, handling and storage operations are a source of $PM/PM_{10}/PM_{2.5}$ emissions which are emitted as point source emissions. The bound agricultural residues and energy crops bales will typically not be a source of suspended $PM/PM_{10}/PM_{2.5}$ emissions until grinded; therefore, no windblown emissions are estimated from the baled biomass stored in the temporary biomass staging area or biomass storage field.

Generally the entire agricultural residues and energy crops grinding and handling operations begins at the process infeed conveyor line. Once the retrieved bales are delivered to the process infeed conveyor line, the biomass grinding, handling and storage system will be a closed system designed with high velocity pickup of particles; therefore, a capture efficiency of 100% is anticipated throughout the system. The agricultural residues and energy crops grinding and handling systems will aspirate to fabric filter dust collectors (baghouses) for control of particulate

emissions. Building openings and ventilation will be kept to a minimum consistent with required operations and good industry safety and health practices.

2.4.2 PM/PM_{10}/$PM_{2.5}$ BACT Review

2.4.2.1 Identify Available Control Options

The following control options have been identified and considered in determining BACT:

- Total or partially enclosed buildings, conveyors, or silos/surge bins without dust collection systems;
- Pneumatic conveying of materials through pipes and duct work; and
- Total enclosures with dust collection systems which collect and control particulate emissions with the use of:
  - Fabric Filter Baghouse;
  - Wet ESPs;
  - Dry ESPs;
  - Venturi Scrubbers; or
  - Cyclones.

2.4.2.2 Eliminate Technically Infeasible Control Options

Enclosures reduce particulate emissions by containing the material and preventing release of particulates or by reducing the wind that can entrain small exposed particles. Enclosures are typically used to capture emissions from operations like grinding and material transferring/handling so that the dust emitted can be collected and vented to a control device.

Types of enclosures typically used for handling dry solids are buildings, silos, hoppers, bins and conveyor covers. In the case of building enclosures, the degree of control is proportional to the degree to which the operation is enclosed. However, in well designed systems, these types of enclosures are totally enclosed.

Solid transfer operations include gravity and pneumatic flow, conveying on belts, front-end loaders and buckets. Pneumatic flow is always

enclosed in pipes. All the other types of transfer operations can be conducted with or without enclosure.

Due to health and safety reasons, most enclosed operations require ventilation to remove the particulates generated by the operations. Although there are numerous devices that are effective at removing particulates from air streams, the most common and effective vent control for enclosures, or pipes and duct work, is the fabric filter baghouse. A baghouse has been established by the industry as the most effective control device for removing particulates from ventilation and conveying air.

Other control devices, such as ESPs, induce an electric field between oppositely charged plates where charged particulates are removed from the exhaust stream. The use of a dry ESP with the suspended particulates is a safety hazard as the particulate dust may explode if exposed to an ignition source such as spark between the charged ESP plates. Wet ESPs, Venturi scrubbers and cyclones are considered technically feasible for use in the receiving operations.

2.4.2.3 Rank Technically Feasible Control Options

Control Technology	Reduction Efficiency
Enclosure	50% to 99+%
Pipes and Duct Work	99+%
Baghouse	99+%
Wet ESP	99+%
Venturi Scrubber	70% to 99+%
Cyclone	≤90%

A baghouse, wet ESP and Venturi scrubber are all capable of achieving emissions reductions of 99% or more when employed with an enclosure or pipes and duct work. However, based on previous performance and application experience, a baghouse is more likely to achieve and maintain 99+% efficiency; and a wet ESP or Venturi scrubber offer no performance or cost advantages. Two disadvantages of a Venturi scrubber are the requirement for water and disposal of a wet waste. Venturi scrubbers will

be utilized in the process design for control of PM when the collected PM can be recovered and either reintroduced into the process stream for further processing, or when the collected PM is viewed as trash (i.e., dirt or other material that will interfere with production). Systems equipped with Venturi scrubbers will also be designed with baghouse control; therefore, the baghouse is the final dust control system of the exhaust stream.

Total enclosure of an emission unit coupled with a dust collection/ventilation system vented to a fabric filter baghouse is the most stringent control technology. Enclosures, piping and duct work must be maintained under negative pressure to achieve maximum control. Negative pressure is created by exhausting air, which is subsequently controlled by a baghouse.

2.4.2.4 *Evaluate Technically Feasible Control Option*

EPA's RBLC database was reviewed to identify particulate control technologies that were potentially applicable to the agricultural residues and energy crops grinding and handling operations. The results of the database search are summarized in Table 2-5.

Table 2–5
Agricultural Residues and Energy Crops Grinding and Handling Operations
RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
Verenium Highlands Ethanol	Biomass Handling	FL-0318	12/10/09	0.005 gr/dscf 5% Opacity	Baghouse
Aventine Renewable Energy	Grain Receiving, Handling, Storage and Hammermilling	NE-0046	09/27/07	0.004 gr/dscf	Baghouse
Koda Energy	Biomass Fuel Handling and Processing	MN-0074	08/23/07	0.005 gr/dscf	Baghouse
Homeland Energy Solutions	Grain Receiving, Storage and Handling	IA-0089	08/08/07	0.004 gr/dscf 0% Opacity	Baghouse
Homeland Energy Solutions	Hammermill	IA-0089	08/08/07	0.004 gr/dscf 0% Opacity	Baghouse

Table 2–5
Agricultural Residues and Energy Crops Grinding and Handling Operations
RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
Archer Daniel Midland	Grain Hammermilling	IA-0088	06/29/07	0.004 gr/dscf 0% Opacity	Baghouse
Alliance Biofuels	Hammermill (4)	OH-3003	05/10/06	0.005 gr/dscf 0% Opacity	Baghouse
Golden Grain Energy	Hammermilling	IA-0082	04/19/06	0.003 lb/hr[1]	Baghouse
Heartland Corn Products	Grain Handling	MN-0062	12/22/05	0.005 gr/dscf	Baghouse
Heartland Corn Products	Hammermills #1 and #2	MN-0062	12/22/05	0.005 gr/dscf	Baghouse
Red Trail Energy	Hammermilling	ND-0020	08/04/04	0.004 gr/dscf 0% Opacity	Baghouse
ACE Ethanol	Milling, Surge Bin	WI-0207	01/21/04	0.004 gr/dscf	Baghouse

Note 1: The Golden Grain Energy BACT limit was established through source testing after construction. The source was originally permitted with emission rates, in pounds per hour (lb/hr), which were equivalent to particulate loadings in excess of 0.005 gr/dscf.

The most effective, technically feasible option identified for control of the emissions from the agricultural residues and energy crops grinding and handling operations is the use of a baghouse. This is the top performing control technology.

2.4.2.5 *Establish BACT*

Based on the review of EPA's RBLC, recent PM/PM_{10} BACT limits range from 0.004 to 0.005 grains per dry standard cubic foot (gr/dscf).

In all of the RBLC cases, the BACT limits for these sources are based on the use of a baghouse to control the grinding/hammermilling and handling PM/PM_{10} emissions. The use of an enclosed system equipped with a baghouse is technically feasible and will be employed. Table 2-6 lists the $PM/PM_{10}/PM_{2.5}$ proposed BACT limits. The $PM_{2.5}$ emission limits are based on the estimated weight fraction used to estimate potential emissions (17% by weight $PM_{2.5}$).

Table 2–6
Agricultural Residues and Energy Crops Grinding and Handling Operations
$PM/PM_{10}/PM_{2.5}$ Proposed BACT Limits

Stack ID	Equipment/ Process	Material Processed	Pollutant	Emission Rate	Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-11120	Floor Sweep System DC	Agricultural Residues and Energy Crops	PM/PM_{10} $PM_{2.5}$	0.27 lb/hr 0.05 lb/hr	0.004 gr/dscf 0.0007 gr/dscf	Fabric Filter Baghouse
EP-11110	Bale Grinder DC	Agricultural Residues and Energy Crops	PM/PM_{10} $PM_{2.5}$	4.93 lb/hr 0.84 lb/hr	0.004 gr/dscf 0.0007 gr/dscf	Fabric Filter Baghouse
EP-11170	Classifier Cyclone # 1 DC	Agricultural Residues and Energy Crops	PM/PM_{10} $PM_{2.5}$	0.74 lb/hr 0.13 lb/hr	0.004 gr/dscf 0.0007 gr/dscf	Fabric Filter Baghouse
EP-11270	Classifier Cyclone # 2 DC	Agricultural Residues and Energy Crops	PM/PM_{10} $PM_{2.5}$	0.74 lb/hr 0.13 lb/hr	0.004 gr/dscf 0.0007 gr/dscf	Fabric Filter Baghouse

2.4.2.6 BACT Compliance

ABBK proposes to meet the agricultural residues and energy crops grinding and handling operations PM/PM_{10} BACT limit based on the average of at least three test runs conducted at each baghouse, and a visible emissions limit of 0% opacity.

2.5 Boiler Fuel and Materials Handling Operations BACT Analysis

2.5.1 Source Emissions

The boiler fuel and materials handling operations are described in detail in Sections 2.1 and 2.7 of the 2011 updated PSD air quality construction permit application. The boiler fuel and materials handling operations are a source of $PM/PM_{10}/PM_{2.5}$ emissions which are emitted as point source emissions.

Positive displacement blowers pneumatically transfer the ground agricultural residues or energy crops to the boiler fuel live-bottom metering bins that gravity-feed the biomass to the boiler. Other conveyor systems will feed the wastewater treatment sludge and enzymatic hydrolysis lignin-rich stillage to the metering bins. There will be no separation of solid biomass in the metering system employed to feed the biomass-fired stoker boiler.

The boiler materials handling will consist of a boiler bottoms ash collection system, and a boiler fly ash collection system, and lime handling system. The

collected fly ash will be conveyed to the fly ash storage silo for rail or truck loadout.

Generally the entire boiler fuel and materials handling operations will be closed systems designed with high velocity pickup of particles; therefore, a capture efficiency of 100% is anticipated. The boiler fuel and materials handling systems will aspirate to fabric filter dust collectors (baghouses) for control of particulate emissions.

2.5.2 PM/PM$_{10}$ BACT Review

2.5.2.1 *Identify Available Control Options*

The same controls identified in Section 2.4.2.1 apply to these sources.

2.5.2.2 *Eliminate Technically Infeasible Control Options*

The technical feasibility discussion presented in Section 2.4.2.2 applies to these sources.

2.5.2.3 *Rank Technically Feasible Control Options*

Total enclosure of an emission unit coupled with a dust collection/ventilation system vented to a fabric filter baghouse is the most stringent control technology. Enclosures (including silos), piping and duct work must be maintained under negative pressure to achieve maximum control. Negative pressure is created by exhausting air, which is subsequently controlled by a baghouse.

2.5.2.4 *Evaluate Technically Feasible Control Option*

EPA's RBLC database was reviewed to identify particulate control technologies that were potentially applicable to the boiler fuel and materials handling operations. The results of the database search are summarized in Table 2-7.

Table 2–7
Boiler Fuel and Materials Handling Operations RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
East Kentucky Power Coop	Ash Handling (Fly Ash Silos)	KY-0100	02/09/10	0.005 gr/dscf	Baghouse
Lake Charles Cogeneration	Sand/Bottom Ash Silos and Day Bins	LA-0231	06/22/09	0.005 gr/dscf	Baghouse
Ohio River Clean Fuels	Fly Ash Handling System	OH-0317	11/20/08	0.005 gr/dscf 20% Opacity	Baghouse and Totally Enclosed Storage Bins, Silos and Truck Loading.
Ohio Clean River Clean Fuels	Coal and Biomass Conveyors/Transfer Towers	OH-0317	11/20/08	0.005 gr/dscf 20% Opacity	Baghouse
Ohio Clean River Clean Fuels	Coal and Biomass Silos	OH-0317	11/20/08	0.005 gr/dscf 20% Opacity	Baghouse
Koda Energy	Ash Handling	MN-0074	08/23/07	0.002 gr/dscf	Baghouse
Koda Energy	Biomass Fuel Handling and Processing	MN-0074	08/23/07	0.005 gr/dscf	Baghouse
Homeland Energy Solutions	Ash Storage and Handling	IA-0089	08/8/07	0.005 gr/dscf 0% Opacity	Baghouse
University of Northern Iowa	Ash Conveying and Ash Silo	IA-0086	05/3/07	0.005 gr/dscf 5% Opacity	Baghouse
University of Northern Iowa	Ash System – Truck Loading	IA-0086	05/3/07	95% Control 5% Opacity	Dust Suppression
Western Greenbrier Cogeneration	Ash Handling	WV-0024	04/26/06	0.010 gr/dscf	Baghouse
Thyssen Krupp Plant #1	Sand Handling	WI-0238	01/12/06	0.005 gr/dscf 20% Opacity	Baghouse
Omaha Public Power District	Fly Ash Waste Dust Collector	NE-0031	03/09/05	0.01 gr/dscf	Baghouse
Thyssen Krupp Plant #1	Sand Handling	WI-0237	12/5/05	0.005 gr/dscf 20% Opacity	Baghouse

The most effective, technically feasible option identified for control of the emissions from the boiler fuel and materials handling operations is the use of a baghouse.

2.5.2.5 *Establish BACT*

Based on the review of EPA's RBLC, recent PM/PM_{10} BACT limits range from 0.002 to 0.01 gr/dscf. In all of the RBLC cases, the BACT limits for these sources are based on the use of a baghouse to control the PM/PM_{10}

emissions. The use of an enclosed system equipped with a baghouse is technically feasible for all systems associated with the boiler fuel and materials handling operations. Table 2-14 lists the $PM/PM_{10}/PM_{2.5}$ proposed BACT limits. The $PM_{2.5}$ emission limits are based on the estimated weight fraction used to estimate potential emissions (either 17% by weight or 50% by weight $PM_{2.5}$).

Table 2–8
Boiler Fuel and Materials Handling Operations $PM/PM_{10}/PM_{2.5}$ Proposed BACT Limits

Stack ID	Equipment/ Process	Material Processed	Pollutant	Emission Rate	Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-11711	Boiler Feed System DC	Agricultural Residues and Energy Crops	PM/PM_{10} $PM_{2.5}$	0.74 lb/hr 0.13 lb/hr	0.004 gr/dscf 0.0007 gr/dscf	Fabric Filter Baghouse
EP-20514	Boiler Bottoms Ash Handling DC #1	Boiler Bottoms Ash	PM/PM_{10} $PM_{2.5}$	0.96 lb/hr 0.48 lb/hr	0.004 gr/dscf 0.002 gr/dscf	Fabric Filter Baghouse
EP-20510	Boiler Fly Ash Handling DC #1	Boiler Fly Ash	PM/PM_{10} $PM_{2.5}$	0.48 lb/hr 0.24 lb/hr	0.004 gr/dscf 0.002 gr/dscf	Fabric Filter Baghouse
EP-20520	Boiler Fly Ash Handling DC #2	Boiler Fly Ash	PM/PM_{10} $PM_{2.5}$	0.48 lb/hr 0.24 lb/hr	0.004 gr/dscf 0.002 gr/dscf	Fabric Filter Baghouse
EP-20512	Lime Handling DC #1	Boiler Sorbent	PM/PM_{10} $PM_{2.5}$	0.07 lb/hr 0.03 lb/hr	0.004 gr/dscf 0.002 gr/dscf	Fabric Filter Baghouse
EP-02710	Bulk Fly Ash Load-Out Silo	Boiler Fly Ash	PM/PM_{10} $PM_{2.5}$	0.96 lb/hr 0.48 lb/hr	0.004 gr/dscf 0.002 gr/dscf	Fabric Filter Baghouse
EP-02711	Bulk Fly Ash Load-Out Silo Spout	Boiler Fly Ash	PM/PM_{10} $PM_{2.5}$	0.96 lb/hr 0.48 lb/hr	0.004 gr/dscf 0.002 gr/dscf	Fabric Filter Baghouse

2.5.2.6 BACT Compliance

ABBK proposes to meet the agricultural residues and energy crops grinding and handling operations $PM/PM_{10}/PM_{2.5}$ BACT limit based on the average of at least three test runs conducted at each baghouse, and a visible emissions limit of 0% opacity.

2.6 Bulk Fly Ash Load-Out Operations BACT Analysis

2.6.1 Source Emissions

Fly ash will be stored in the bulk fly ash load-out silo. Fly ash will be shipped off-site either by trucks or rail cars that are loaded from the elevated load-out silo system using a load-out spout. The load-out spout will be either sealed to the rail car or truck and maintained under negative pressure, or loadout will occur within a total enclosure, either of which will be controlled by the bulk fly ash load-out silo

spout dust collector (DC-02711). There will be no fugitive emissions generated from this activity.

2.6.2 PM/PM$_{10}$ BACT Review

2.6.2.1 Identify Available Control Options

The same controls identified in Section 2.3.2.1 apply to this source.

2.6.2.2 Eliminate Technically Infeasible Control Options

The technical feasibility discussion presented in Section 2.3.2.2 applies to this source.

2.6.2.3 Rank Technically Feasible Control Options

Control Technology	Reduction Efficiency
Partial or Total Enclosure	50% to 99+%
Baghouse	99+%
Wet ESP	99+%
Venturi Scrubber	70% to 99+%
Cyclone	≤90%

The reduction in emissions from the decrease in wind velocity due to an enclosure is expected to be up to 100% when compared to processes in the open. A baghouse, wet ESP and Venturi scrubber are all capable of achieving additional emissions reductions of 99% or more. However, based on previous performance and application experience, a baghouse is more likely to achieve and maintain 99+% efficiency; and a wet ESP or Venturi scrubber offer no performance or cost advantages. Two disadvantages of a Venturi scrubber are the requirement for water and disposal of a wet waste.

Total enclosure of an emission unit coupled with a dust collection/ventilation system vented to a fabric filter baghouse is the most stringent control technology.

2.6.2.4 Evaluate Technically Feasible Control Option

EPA's RBLC database was reviewed to identify particulate control technologies that were potentially applicable to the fly ash handling

operations. There was limited information contained on the RBLC database that was specific to fly ash load-out to trucks. The results of the database search are summarized in Table 2-9.

Table 2–9
Boiler Fuel and Materials Handling Operations RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
Ohio River Clean Fuels	Fly Ash Handling System	OH-0317	11/20/08	0.005 gr/dscf 20% Opacity	Baghouse and Totally Enclosed Storage Bins, Silos and Truck Loading.
Big Cajun Power Plant	Ash Truck Loading	LA-0223	01/08/08	Lb/Hr Limit	Closed Vent System That Vents Back Into the Ash Silo
Little Gypsy Generating Plant	Bed Ash Loading and Unloading to Trucks	LA-0221	11/30/07	Lb/Hr Limit	Closed Vent System That Vents Back Into the Ash Silo
Little Gypsy Generating Plant	Fly Ash Loading to Trucks	LA-0221	11/30/07	Lb/Hr Limit	Closed Vent System That Vents Back Into the Ash Silo
University of Northern Iowa	Ash System – Truck Loading	IA-0086	05/3/07	95% Control 5% Opacity	Dust Suppression
NRG Texas Coal Handling	Fly Ash Truck Loading	TX-0507	4/13/06	Lb/Hr Limit	None
Cleco Power Rodemacher Brownfield	Ash Loading	LA-0202	02/23/06	Lb/Hr Limit	Truck Loading Chute Seals to Truck with Negative Pressure Vent Back to Silos

2.6.2.5 *Establish BACT*

As previously stated, the load-out spout will be either sealed to the rail car or truck and maintained under negative pressure, or loadout will occur within a total enclosure. This type of control is consistent with recent BACT determinations for similar sources.

2.6.2.6 *BACT Compliance*

A Fugitive Dust Control Plan will be developed and will detail the work practices to be implemented to reduce fugitive emissions from the fly ash load-out operations. ABBK will provide a copy of the Fugitive Dust Control Plan and associated documentation to KDHE upon request to demonstrate compliance with BACT.

2.7 Fermentation and Distillation BACT Analysis

2.7.1 Source Description

The CO_2 generated from the biomass co-fermentation process (Area 16000) will be routed through the enzymatic hydrolysis fermentation CO_2 scrubber (S-18185). The rated control efficiency will be equal to or greater than 99%. The CO_2 generated from the biomass ethanol recovery process (Area 18000) will be routed through the enzymatic hydrolysis distillation vent scrubber (S-18180). The distillation vent scrubber vent feeds into the enzymatic hydrolysis fermentation CO_2 scrubber (S-18185) for further control efficiency. The non-condensibles generated in areas 12000, 16000, and 19000 from the biomass process vents will be routed to either the biomass-fired boiler or flare for destruction.

The vent streams routed to the scrubbers are expected to be saturated with water since the process tanks contain primarily CO_2 and water. These vent streams also are expected to contain VOC and HAPs. The scrubbers will be packed-tower wet scrubbers, which allow for ethanol vapors to be collected for a higher product yield, however the units also provides VOC and HAP emission control. The scrubber systems will recover nearly all of the ethyl alcohol (ethanol) from the vapor stream and return the ethanol to the process downstream. The water from the wet scrubbers is pumped back into the process for recycling. The distillation vent scrubber vent feeds into the enzymatic hydrolysis fermentation CO_2 scrubber (S-18185) for further control efficiency and is discharged through the fermentation CO_2 scrubber stack (EP-18185).

A detailed engineering evaluation of the fermentation and distillation vent streams identified the potential for other PSD pollutants, including condensable PM, NO_2 and H_2S. Although this source's VOC and H_2S emissions do not require PSD review, the condensable PM and NO_2 must undergo PSD review. It should be

noted that the wet scrubbers are an integral part of the process, as well as a control device for VOC, HAPs, PM, H_2S and NO_2. Wet scrubbers allow for product that would otherwise be lost in the vent streams to be captured and returned to the process stream. Wet scrubbers increase the efficiency of the process and the biorefinery would not operate without the wet scrubbers.

2.7.2 Condensable PM and NO_2 BACT Review

2.7.2.1 Identify Available Control Options

Condensable PM is formed after the stream exhausts from the scrubber and is due to fine particles, including aerosols, condensing at ambient air conditions. Wet scrubbers often achieve higher levels of condensable PM control as the scrubbers help to condense the condensable PM during the scrubbing. NO_2 is a trace containment present in the vent streams ducted to the fermentation packed-tower wet scrubber for control. NO_2 control through the use of the scrubber is estimated to be greater than 95% control. Based on the review of the RBLC database and other technical sources of information, there are no additional control options for condensable PM and NO_2 in addition to the packed-tower wet scrubbers that will be employed as part of the fermentation and distillation process.

2.7.2.2 Establish BACT

Based on the use of the packed-tower wet scrubbers for VOC and HAP control, the most effective, technically feasible option identified for the control of condensable PM and NO_2 is also the use of packed-tower wet scrubbers only for the fermentation and distillation operations associated with ethanol production. Table 2-10 lists the proposed BACT limits.

Table 2–10
Fermentation and Distillation Operations VOC Proposed BACT Limits

Stack ID	Equipment/ Process	Emission Rate	Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-18185	EH Fermentation CO_2 Scrubber	Condensable PM: 0.10 lb/hr NO_2: 0.08 lb/hr	Total PM: 0.1 lb/hr NO_2: 0.07 lb/hr	Wet Scrubber

2.7.2.3 *BACT Compliance*

ABBK proposes that the pound per hour limits be considered BACT and used for compliance purposes for enzymatic hydrolysis fermentation CO_2 scrubber (S-18185). The proposed BACT limits in pound per hour applies during all times, including during SSM, and are based on an average across the fermentation batch cycle during the performance testing of the source.

The proposed BACT limit is in units of pounds per hour, rather than a throughput based limit for several reasons. First, the estimated scrubber performances are based on a 95+% control of NO_2 emissions, as calculated using material balance data at the wet scrubbers and a process simulator program. When outlet concentrations are lower, percent control efficiencies may decline slightly; however, the lb/hr emission rate would also decline. Second, there are multiple vent streams entering the scrubbers. Thus, it would be difficult to develop a single throughput based limit for the wet scrubbers that can account for these vents. Third, the condensable PM and NO_2 emissions from the fermentation and distillation operations vary for a number of reasons including the fermentation process in batch mode, thus throughput is not necessarily a good indication of emissions. Finally, the ability to determine compliance with a throughput based limit is extremely difficult due to the factors involved in determining both emissions and throughput. The ability to determine compliance with a pound per hour limit is readily demonstrated using standard EPA test methods.

2.8 Cogeneration Biomass-Fired Stoker Boiler BACT Analysis

2.8.1 Source Emissions

The cogeneration plant will employ one water-cooled vibrating grate (stoker) boiler. The boiler will be capable of producing 325,000 pounds per hour of 920 pound-force per square inch gauge (psig) /750 °F steam. The high pressure steam supplies a single condensing-extraction steam turbine generator nominally rated at 22 Megawatts of electricity (MWe). Electrical power will be supplied to the facility. Power sales to the grid are not foreseen at this time.

Enzymatic hydrolysis process steam is extracted from the turbine at a lower pressure from extraction ports. Boiler feedwater preheater steam and deaeration steam is also extracted from the turbine from extraction ports. Exhaust steam is condensed under vacuum against cooling water in the cooling water tower. The stoker boiler's maximum design heat input is 500 million British thermal units per hour (MMBtu/hr). The stoker boiler is capable of burning a combination of raw biomass (consisting of corn stover, wheat straw, milo (sorghum) stubble, corn stover, switchgrass, and other opportunity feedstocks that are available), enzymatic hydrolysis residuals (including lignin-rich stillage cake and thin stillage syrup), particles collected during biomass grinding, NCG vent streams, wastewater treatment sludge and biogas. Natural gas will be used during start-up periods as required per manufacturer recommendations. The stoker boiler will also be capable of firing on natural gas during normal operations as needed at a limited capacity, as well as firing on a combination of natural gas, liquid fuel (i.e. enzymatic hydrolysis thin stillage syrup) and biogas in the event of a solid fuel failure. The cogeneration process will utilize up to 812 dry tons/day of fuel feedstock.

2.8.2 RBLC Biomass-Fired Boilers

EPA's RBLC database was reviewed to identify biomass-fired boilers with heat inputs greater than 250 MMBtu/hr permitted after January 1, 2003 with BACT limits established for PSD pollutants being reviewed in the ABBK BACT analysis. There were 23 "new construction" permitted boilers identified that were considered similar to the proposed ABBK boiler based on a search of the RBLC database under the Process Type 11.000 – *Utility and Large Industrial Size Boilers/Furnaces (>250 MMBtu/hr),* Subcategory Type 11.120 – Biomass. The boilers identified are summarized in Table 2-11. The boiler types include both stoker and fluidized bed combustion boilers. Appendix A contains the detailed summary table for the biomass-fired boilers reviewed as part of BACT analysis.

Table 2–11
RBLC Biomass-Fred Boilers Permitted After January 1, 2000

Facility	Primary Fuel Type	Note	RBLC ID	Permit Date	Boiler Size (MMBtu)
Georgia Power Co., Mitchell Steam Generation Plant	Biomass	1	GA-0140	12/03/10	<250 Actual Unk
Laidlaw Berlin Biopower	Wood	2	NH-0018	07/26/10	1,013
NRG Energy Montville Power	Wood	3	CT-0156	04/06/10	600

Table 2–11
RBLC Biomass-Fred Boilers Permitted After January 1, 2000

Facility	Primary Fuel Type	Note	RBLC ID	Permit Date	Boiler Size (MMBtu)
Boise Cascade Corp, Boise White Paper	Wood		AL-0250	03/23/10	435
Lindale Renewable Energy	Wood	4	TX-0553	01/08/10	674
Aspen Power Lufkin Generating Plant	Wood	5	TX-0555	10/26/09	693
Clean Power Berlin	Wood	6	NH-0016	09/25/09	1,013
Concord Steam Corporation	Wood	7	NH-0015	02/27/09	305
Yellow Pine Energy Company	Wood Waste	8	GA-0132	12/03/08	1,450
U.S. Sugar Corp Clewiston Sugar Mill and Refinery	Bagasse	9	FL-0301	12/06/07	738
Koda Energy	Biomass	10	MN-0074	08/23/07	308
Simpson Tacoma Kraft Co.	Wood Waste	11	WA-0335	05/22/07	595
Smurfit Stone Container Corp. Stevenson Mill	Wood Waste		AL-0223	07/14/06	620
Archer Daniels Midland Co. Northern Sun	Biomass	12	ND-0022	05/01/06	280
South Point Biomass Generation	Wood		OH-0307	04/04/06	318
Boise Cascade Corp White Paper, Wallula Mill	Wood / Bark		WA-0337	02/01/06	343
Sierra Pacific Industries Skagit County Lumber Mill	Bark and Waste Wood		WA-0327	01/25/06	430
Potlatch Corporation, Ozan Unit	Unk		AR-0083	07/26/05	Unk
Darrington Energy Cogeneration Power Plant	Wood Waste	13	WA-0329	02/11/05	403
Inland Paperboard and Packaging Bogalusa Mill	Fuel Oil	14	LA-0188	11/23/04	787.5
Public Service of New Hampshire Schiller Station	Biomass	15	NH-0013	10/25/04	720
Inland Paperboard and Packaging Rome Linerboard Mill	Bark, Wood Residue, Waste Wood	16	GA-0114	10/13/04	856
U.S. Sugar Corp Clewiston Sugar Mill and Refinery	Bagasse	17	FL-0257	11/18/03	936

Note 1: Coal-fired Steam Generating Unit (155 MW) being converted to a biomass-fired stoker Steam Generating Unit (96 MW). Boiler permitted to burn biomass fuel, including clean wood chips (e.g. pine chips, hardwood chips, pallets and reels), whole tree chips (e.g. trees, shrubs, unmerchantable fuel wood, and thinnings), forest residues (e.g. tops, limbs and bark), manufacturer's residues (e.g. sawdust and sanders dust), and hulls (e.g. peanut and pecan hulls). Ultra low sulfur (i.e. <0.0015%) No. 2 fuel oil, or biodiesel or blend of previous two fuels may be burned for start-up and shutdown, and to assist in achieving peak load and flame stabilization.

Note 2: The maximum heat input rate of the boiler will be 1,013 million British Thermal Units per hour (MMBtu/hr) assuming fuel with a moisture content of 50%.The boiler will also be equipped with four oil fired burners for use during startup only. Each oil burner will have a maximum heat input rate of 60 MMBtu/hr.

Note 3: Natural gas and No. 6 Oil-fired steam generating unit (82 MW) being converted to vibrating grate stoker wood biomass boiler to produce 40 MW, as well as maintaining ability to combust liquid fuel or natural gas to full 82 MW capacity, with a 7% annual capacity limit.

Note 4: 50 MW net power to grid using biomass fuels. The plant will burn between 54 and 73 tons per hour (tph) of biomass and will operate up to 8,760 hours/year. The plant is designed to burn 100% green wood or green wood mixed with up to 50% construction and demolition wood wastes and B100 Bio-Diesel will be used during startup.

Note 5: Aspen Power is proposing to install a 692.6 MMBtu/hr stoking grate wood waste derived fuel boiler which will drive a 45 MW steam turbine generator. The fuel will consist of untreated wood waste (primarily logging or lumber mill residue and wood products that have been shaped and/or assembled with only mechanical fasteners). Per the agency, neighborhood opposition resulted in the voluntary installation of SCR for NOx

control and an oxidation catalyst (if needed) for CO control. This boiler is under construction and no performance testing has been completed.

Note 6: 390 MMBtu/hr - Wood chips-equivalent to 40.75 tons per hour assuming average moisture content of 45% by weight. 90 MMBtu/hr from natural gas on boiler startups, at a maximum of 88,235 scf/hr.

Note 7: 305 MMBtu/hr - Wood chips. 90 MMBtu/hr from natural gas on boiler startups.

Note 8: Boiler can fire low sulfur distillate fuel or propane at S&S; can fire 95% metal free tire-derived fuels as supplemental fuels up to 15% on a MMBtu/hr basis on a trial basis only. NOx emission limit modified from original BACT. SO_2 control modified from original BACT.

Note 9: Project will add wood chips as a seasonal start-up fuel and to support minimal refinery operations during crop off season. Wood chips limited to an annual capacity factor of 25%.

Note 10: Biomass consists of untreated wood, oat hulls, malt and grain by-products.

Note 11: Permitted fuels include 89% wood waste (including recycled cardboard), 8% wastewater treatment sludge and 3% No. 6 fuel oil.

Note 12: Permitted fuels include hulls (sunflower and soybean hulls), biomass fuels, creosote-treated railroad ties and clean wood. Biomass fuels consist of approximately 70% to 95% hulls, 2.5% to 3% wax and 6% vegetable oil.

Note 13: The boiler is limited to waste wood from lumber manufacturing, whole trees or similar natural vegetation. Oil with a sulfur limit of 0.05% or less may be used for start-up or to maintain good combustions.

Note 14: Boiler is permitted for 568.85 MMBtu/hr when combusting fuel oil and 374.0 MMBtu/hr when combusting secondary fiber (OCC) rejects. Fuel oil limited to <10% annual capacity

Note 15: 720 MMBtu/hr heat input when combusting biomass. Permitted wood fuel includes whole tree chips, untreated by-products or residue from forest products manufacturing operations, stump grindings or ground pallets. 635 MMBtu/hr heat input when combusting coal with a maximum sulfur content of 1.5 lb/MMBtu short term and 1.0 lb/MMBtu 3-month average. Coal is a backup fuel, but plant can fire coal up to 8,760 hours per year. All emission limits based on wood fuel use.

Note 16: Permitted fuels include bark, wastewater treatment sludge, tire-derived fuels, fuel oil, and NCG.

Note 17: Permitted fuels include bagasse and distillate oil (<0.05% sulfur by weight).

2.8.3 NO_x BACT Review

Nitrogen oxides are formed during combustion by two major mechanisms: thermal formation (thermal NOx) and fuel formation (fuel NOx). Thermal NOx results from the high temperature oxidation of nitrogen and oxygen. In this mechanism, nitrogen is supplied from air which is approximately 79% nitrogen by volume. Thermal NOx formation is primarily dependent on combustion temperature. Thermal NOx formation increases exponentially with temperature and becomes significant at temperatures above 2,200°F. Fuel NOx results from the direct oxidization of organic nitrogen in the fuel.

In the case of solid biomass, it is expected that minimal thermal NOx will be created due to the low combustion temperature that will be targeted. Therefore, NOx emissions resulting from the combustion of solid biomass are primarily from fuel nitrogen combustion. The NOx emission factor for the boiler fuel was based on a blended biomass nitrogen content of 1.40 to 1.54% by weight when the boiler is fired predominately by solid fuel, with approximately 11% of the fuel nitrogen converting to NOx. The calculated uncontrolled emission rate based on fuel properties and engineering estimates for N-to-NOx conversion is between 0.70 and 0.76 lb/MMBtu.

The U.S. Department of Energy (DOE) is proposing to provide federal funding to ABBK to support the final design, construction, and startup of the biomass-to-ethanol and biomass-to-energy production facility. The DOE funding is based on the proposed facility design. ABBK's basic or fundamental business purpose/objective for this project is dependent on the biomass-fired boiler design as proposed. The use of the proposed fuel is critical to the project; therefore, analysis of the fuel compared to other fuels is not within the scope of this BACT analysis.

Further, the U.S. EPA has established performance standards for a number of air pollution sources in 40 CFR Part 60, New Source Performance Standards (NSPS). These NSPS usually represent a minimum level of control that is required of a new source. NSPS Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, regulates emissions from steam generating units that are capable of combusting more than 29 megawatts (100 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and for which construction or modification is commenced after June 19, 1984. The proposed biomass-fired stoker boiler was reviewed for applicability to 40 CFR §60.44Db(d), which states that an affected facility which simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall not cause to be discharged into the atmosphere from that affected facility any gases that contain NOx in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas. ABBK is requesting to limit the annual capacity factor for natural gas to 10% or less as allowed in 40 CFR §60.44Db(d); therefore, the NOx limits in 40 CFR §60.44Dd will not apply to the proposed boiler.

2.8.3.1 *Identify Available Control Options*

There are two major technology categories for controlling NOx emissions from the biomass-fired boiler: combustion controls and post-combustion controls. Combustion and non-combustion controls may be used together to achieve the lowest emission rates. The following control options have been identified and considered in determining BACT for the

biomass-fired stoker boiler when combustion the blended biomass fuel (including natural gas):

Combustion Controls

- Boiler Type Selection;
- Burner Optimization;
- Over-Fire Air (OFA);
- Low-NOx Burners; and
- Flue Gas Recirculation (FGR).

Post-Combustion Controls

- Selective Catalytic Reduction (SCR);
- Regenerative SCR (RSCR); and
- Selective Non-Catalytic Reduction (SNCR).

2.8.3.2 Eliminate Technically Infeasible Control Options

Boiler Type Selection

As part of the DOE funding of this project, ABBK is proposing to construct a state-of-the-art biomass-to-ethanol and biomass-to-energy production facility. The biomass-to-energy facility will combust process residuals from the enzymatic hydrolysis ethanol production process, as well as other process residuals and raw biomass. There is no boiler operating in the U.S. at the scale proposed by ABBK (500 MMBtu/hr, 325,000 pounds per hours 920 psig /750 °F steam, 22 Megawatts of electricity (MWe) with the proposed fuels. The proposed boiler is part of an integrated facility that is helping the U.S. to meet the mandates of the Energy Policy Act of 2005 (EPACt2005), Section 932, which directs the Secretary of Energy to conduct a program of research, development, demonstration, and commercial application for bioenergy, including integrated biorefineries that can produce biopower, biofuel and bioproducts. The proposed boiler must be capable of burning a combination of raw biomass (consisting of corn stover, wheat straw, milo (sorghum) stubble, corn stover, switchgrass, and other opportunity feedstocks that are available), enzymatic hydrolysis residuals (including lignin-rich stillage cake and thin stillage syrup),

particles collected during biomass grinding, NCG vent streams, wastewater treatment sludge and biogas.

Due to the use of "emerging technology" in the selection of the boiler fuel, ABBK has discussed with both stoker-type boiler vendors and fluidized bed combustion (FBC) boiler vendors and has decided that due to the inherent high alkalinity, the ash content of the fuel, and use of enzymatic hydrolysis residuals consisting of lignin-rich stillage cake and thin stillage syrup as the primary boiler fuel, that the stoker-type boiler poses the lowest overall risk to the success of the project. A thorough review of recently permitted biomass-fired boilers was conducted as part of this BACT analysis and the results support ABBK's selection of a stoker-type boiler. Several recent BACT determinations have been made for stoker-type biomass-fired boilers.

Burner Optimization

Burner optimization is usually the first method used to control NOx formation. Optimization is achieved by modifying boiler-operating conditions. Excess air control, boiler fine tuning and balancing the fuel and air flow to the burner will achieve minimum NOx formation reductions. The biomass-fired boiler will be optimized for maximum combustion efficiency and the boiler operating parameters will be continuously monitored. However, the nature of the biomass to be combusted may result in continuous changes to the optimization points. Reducing excess air in combination with fine tuning the boiler could achieve NOx formation reduction rates from 10% to 20%.

Over-Fire Air

In a stoker boiler, when primary combustion uses a fuel-rich mixture, OFA helps to complete the combustion process. Because the mixture is always off-stoichiometric during combustion, the combustion temperature is reduced. After all other stages of combustion, the remainder of the fuel is oxidized in the OFA zone. The biomass-fired boiler will utilize an OFA system to promote vigorous mixing of the combustion gases to maximize combustion efficiency and reduce pollutant emissions. OFA is a

combustion staging process that is used to create an oxygen depleted zone where unburned hydrocarbons act to reduce the NOx that is formed near the grate.

Low-NOx Burners

Low-NOx burners control thermal NOx formation by avoiding high temperature combustion zones and uneven oxygen distribution. This is accomplished by burner designs that carefully control the mixing of fuel and combustion air. Generally, use of low-NOx burners requires a wall-fired furnace and pulverized biomass fuel that is burned in suspension with coal or natural gas. Low-NOx burners have not been commercially applied to FBC or stoker boilers. Therefore, low-NOx burner technology is not considered a technically feasible control option for control of NOx from the combustion of the solid biomass. Low-NOx burners can be employed for natural gas firing. These types of burners will be utilized on the biomass-fired boiler for natural gas combustion.

Flue Gas Recirculation

Flue gas recirculation for NOx control includes gas recirculation into the furnace or into the burner. In this technology 20% to 30% of the flue gas (at 350-400°C) is re-circulated and mixed with the combustion air. The resulting dilution in the flame decreases the temperature and availability of oxygen therefore reducing thermal NOx formation. Because of the properties of the solid biomass and the boiler furnace (combustion zone) design, FGR cannot be implemented on these boilers. Therefore, FGR technology is not considered a technically feasible control option, and is not considered further in this BACT analysis.

Selective Catalytic Reduction and Regenerative SCR

SCR systems are typically implemented on stationary fossil fuel combustion units such as electrical utility boilers, industrial boilers, process heaters, gas turbines and reciprocating internal combustion engines. Theoretically, SCR systems can be designed for NOx removal efficiencies up to 100%. Commercial coal-, oil- and natural gas-fired SCR systems are often designed to meet control targets of over 90%. However,

maintaining this efficiency is not always practical from a cost standpoint. In practice, SCR systems operate at efficiencies in the range of 70% to 90%.

SCR systems use a nitrogen reducing agent (generally ammonia, NH_3) to reduce NOx emissions by injecting NH_3 into the exhaust gas upstream of a catalyst. Ammonia absorbed on the catalyst surface selectively reacts with the NOx in the presence of oxygen to form nitrogen (N_2) and water. The chemical reactions involved in the SCR process are:

$$NH_3 + NO + {}^1/_4O_2 \longrightarrow N_2 + {}^3/_2H_2O$$

$$NH_3 + {}^1/_2NO_2 + {}^1/_4O_2 \longrightarrow {}^3/_2N_2 + {}^3/_2H_2O$$

Catalyst performance is optimized when the oxygen level in the exhaust gas stream is above 2% to 3%. Commercial applications of this technology have been demonstrated over an extended temperature range from 300°F to 1000°F. The catalyst material that is used defines the optimal temperature range. Heat recovery steam generation is a beneficial part of the facility's boiler system and therefore, inlet temperatures can be reduced from 1300°F+ at the boiler furnace (combustion zone) to the SCR optimum temperature range of 480°F to 800°F.

The advantages of an SCR include higher NOx reductions than SNCR. Also SCR reactions occur with a lower and broader temperature range than SNCR, and the SCR does not require modifications to the combustion unit. Disadvantages of the SCR are significantly higher capital and operating costs than SNCR; large volume of reagent and catalyst required; potential downstream equipment cleaning; and addition of ammonia in waste gas stream and ash. Ammonia in the waste gas stream is an additional environmental concern. Most SCR systems have been installed to reduce NOx emissions in exhaust streams with relatively little particulate matter, like natural gas-fired boilers and turbines.

The proposed boiler will combust a blended biomass fuel that has a calculated ash content of approximately 13%. The estimated ash content of this blended biomass fuel is considerably higher than wood, which has an ash content of approximately 1%; or natural gas, which has a negligible

ash content. Further, the blended biomass will pose other significant technical challenges due to the higher levels of sulfur (0.98% by weight); presence of alkaline and alkaline-earth metals such as sodium, potassium and calcium; and high concentrations of hydrochloric acid (HCl).

In a high ash environment, there are four basic mechanisms for deactivation of an SCR catalyst which reduce or eliminate the ability of the SCR system to control NOx emissions: 1) Poisoning; 2) Plugging; 3) Fouling; and 4) Erosion. *Poisoning* results from a chemical attack on the surface of the catalyst. *Plugging* involves microscopic blockage of catalyst pores by small ash particles. *Fouling* involves macroscopic blockage of the catalyst through a build-up of ash. *Erosion* of the catalyst surface is due to the abrasive nature of the particles in a high dust environment and can lead to deactivation through the wearing away of the catalyst surface.

Tail gas SCR systems are an SCR system where the catalyst is located downstream of the SO_2 and particulate control device to reduce deactivation problems. The higher concentrations of SO_2 will still exacerbate the catalyst deactivation even with the placement of the SCR catalyst downstream of the SO_2 and PM control devices. In a tail gas SCR arrangement, the ammonia injection rate to the SCR must be carefully controlled to prevent excess ammonia, called ammonia slip, from being carried over since there is no pollution control system downstream of the tail gas SCR system.

Catalysts used in SCR systems can be divided into three categories based on the temperature range in which they are designed to operate. High temperature catalysts operate in the 650°F to 1000°F range, medium temperature in the 500°F to 725°F range, and low temperature in the 300°F to 680°F range.

Low-temperature catalysts, which operate at the expected boiler exhaust temperature, are typically used to reduce NOx emissions in relatively "clean" (i.e., low particulate and low sulfur) exhaust from natural gas combustion sources. While wood is typically not considered a high-sulfur

fuel, corn stover is expected to contain higher levels of sulfur (0.98% by weight). Low temperature catalysts readily convert a portion of any SO_2 in the exhaust to SO_3, which then would react with the injected ammonia to produce ammonium sulfate and sulfite, which are highly corrosive salts. Because low temperature catalysts are highly sensitive to SO_3 poisoning, low temperature catalysts are considered not technically feasible.

Medium- and high-temperature catalysts are less prone to complications from sulfur and particulate in the exhaust, but both would require exhaust reheat. Regenerative SCR (RSCR) systems have been developed recently to make application of a medium temperature SCR system more economical by using a regenerative ceramic bed to recover heat from the reheated flue gases to limit the use of the reheat fuel. Also, because reheat fuel is kept to a minimum, it facilitates positioning the NOx reduction system after a dust collection device, which serves to prolong the life of the catalyst. Similar to a tail gas SCR system, in an RSCR arrangement, the ammonia injection rate to the SCR must be carefully controlled to prevent excess ammonia.

Because of the high potential for catalyst deactivation, traditional SCR is not a technically feasible NOx control technology for the biomass-fired boiler. However, based on the recent successful application of tail gas SCR or RSCR to wood-fired boilers, tail gas SCR or RSCR has been proven to be a technically feasible control option for the biomass-fired boiler. The reduction potential with a tail gas SCR or RSCR is approximately 60% to 80% based on BACT determinations contained in the RBLC database.

Selective Non-Catalytic Reduction

SNCR systems are capable of NOx reduction efficiencies in the range of 30% to 50%. SNCR systems are typically installed on a wide range of boiler configurations including: dry bottom wall-fired and tangentially-fired units; wet bottom units; stokers; and fluidized bed units. These units fire a variety of fuels such as coal, oil, gas, biomass and waste.

SNCR systems reduce NOx by injecting ammonia into the process where the ammonia will selectively react with NOx to produce nitrogen and water. The NOx reduction reaction occurs at temperatures between 1600°F to 2100°F. In addition to operating temperature requirements, good mixing and sufficient residence time must be present. As the desired NOx removal efficiency is increased, the amount of ammonia slip increases due to the non-uniform distribution of reacting gases and the stoichiometric ammonia to NOx ratio required to achieve higher reductions. Issues related to ammonia transport and storage, ammonia slip emissions and the associated increase in PM/PM_{10} emissions are all considerations when specifying an SNCR control system.

For SNCR, ammonia injection nozzles would be positioned in the combustion zone to use the relatively high temperatures there to promote the reaction of NOx and ammonia. The SNCR system can be located inside the furnace because SNCR systems do not rely on a catalyst which is subject to deactivation as discussed previously from particulate matter in the flue gases. The relative simplicity and effectiveness of SNCR systems has resulted in SNCR becoming the most common add-on NOx control technology for larger sized solid fuel-fired boilers that operate under steady load; however, the potential for ammonia slip is greater with SNCR.

The advantages of an SNCR system are that capital and operating costs are among the lowest of all NOx reduction methods. Disadvantages of the SNCR are lower NOx reductions than SCR; potential downstream equipment cleaning; and addition of ammonia in waste gas stream and ash.

2.8.3.3 Rank Technically Feasible Control Options

Control Technology	Reduction Efficiency
Tail Gas SCR or RSCR on Biomass-Fired Boilers	60% to 80%
SNCR on Biomass-Fired Boilers	30% to 50%
Combustion Controls/OFA/ Burner Optimization	10% to 20%

2.8.3.4 *Evaluate Technically Feasible Control Options*

EPA's RBLC database was reviewed to identify technologies used to control NOx emissions from biomass-fired boilers with heat inputs greater than 250 MMBtu/hr. No facilities in the RBLC database burn the same types of fuels as ABBK. Most biomass boilers in the database burn various types of wood/wood waste in conjunction with other fuels, including coal, natural gas, fuel oil, wastewater sludge, tire-derived fuel, railroad ties and other non-municipal wastes or production by-products.

The results of the database search from January 1, 2001 to present are presented in detail in Appendix A. Table 2-12 summarizes the information through January 1, 2003 since the permitting for biomass-fired boilers appears to have become more stringent in recent years due to state control requirements, public pressures, renewable fuel tax credits and non-attainment issues.

Table 2–12
Biomass-Fired Boilers RBLC Summary for NOx Emissions

Facility	RBLC ID	Emission Limit (lb/MMBtu)	Basis	Control	Verified
Laidlaw Berlin Biopower	NH-0018	0.06	LAER	SCR	No
NRG Energy Montville Power	CT-0156	0.06	LAER	RSCR	No
Boise Cascade Corp, Boise White Paper	AL-0250	0.3	BACT	N/A	Yes
Lindale Renewable Energy	TX-0553	0.15	BACT	SNCR	Unknown
Aspen Power Lufkin Generating Plant	TX-0555	0.075	Voluntary	SCR	Unknown
Clean Power Berlin	NH-0016	0.065	LAER	SCR	No
Concord Steam Corporation	NH-0015	0.065	LAER	SCR	No
Yellow Pine Energy Corporation	GA-0132	0.07	BACT	SNCR	No
U.S. Sugar Corp Clewiston Sugar Mill and Refinery	FL-0301	0.31	BACT	Boiler Design and Operation (Including Overfire Air)	Yes
Koda Energy	MN-0074	0.25	BACT	SNCR with Secondary Overfire Air[4]	Unknown
Simpson Tacoma Kraft	WA-0335	0.2	BACT	Overfire Air/Proper Combustion	No, Under Review

Table 2–12
Biomass-Fired Boilers RBLC Summary for NOx Emissions

Facility	RBLC ID	Emission Limit (lb/MMBtu)	Basis	Control	Verified
Archer Daniels Midland Co. Northern Sun	ND-0022	0.2	BACT	Proper Combustion	Yes
Biomass Energy, South Point Biomass Generating	OH-0307	0.44	State BAT	SCR	No
Boise Cascade Corp, Wallula	WA-0337	0.3	BACT	OFA	Unknown
Sierra Pacific Industries Skagit County Lumber Mill	WA-0327	0.13	BACT	SNCR	Unknown
Darrington Energy Cogeneration Power Plant	WA-0329	0.12	BACT	SNCR	Unknown
Inland Paperboard and Packaging Bogalusa Mill	LA-0188	0.45 (1-Hour Max)	BACT	Overfire Air, Good Combustion Practices	Unknown
Public Service of New Hampshire Schiller Station	NH-0013	0.075	Other	SNCR, RSCR	Yes
U.S. Sugar Corp Clewiston Sugar Mill and Refinery	FL-0257	0.14	BACT	SNCR	No

EPA's RBLC database lists 19 NOx limitations for biomass-fired boilers with heat inputs greater than 250 MMBtu/hr permitted after January 1, 2003 (see Table 2-11 for the biomass-fired boilers reviewed). The RBLC database indicates a wide range of NOx control as BACT, including no control, combustion control, SCR and SNCR. The BACT emission rates range from 0.07 to 0.31 lb/MMBtu (based on either 24-hour or 30-day rolling averages).

Several lowest achievable emission rate (LAER) determinations were relied upon for the determination that SCR/RSCR is technically feasible for the biomass-fired boiler.

Energy Impacts

Although the use of tail gas SCR or RSCR can achieve lower NOx emission rates, tail gas SCR or RSCR would have other adverse energy impacts. The energy impacts from the application of the technology would include an

electricity penalty from the increase pressure drop across the system and a natural gas penalty for flue gas reheat.

Environmental Impacts

The primary negative environmental effect of a tail gas SCR or RSCR is the creation of natural gas combustion-related pollutant emissions such as NOx, CO and CO_2. Also, the biomass-fired stoker boiler's footprint would be expected to increase requiring a redesign of the proposed facility layout and the use of additional raw materials for construction.

Economic Impacts

The cost for the tail gas SCR or RSCR will include both the capital costs for the SCR/RSCR and ancillary equipment. In addition, the SCR/RSCR system will have natural gas flue gas reheating costs, auxiliary power requirements, catalyst replacement costs, maintenance costs, and administrative costs.

Appendix A contains a detailed analysis of the SCR and SNCR control options that are technically feasible. Table 2-13 includes a summary of the SCR and SNCR costs and the estimate of each control costs.

Table 2–13
Cost Effectiveness of the NOx Control Technology Options for the Biomass-Fired Boiler

Parameter	No Control	Baseline – SNCR	Tail Gas SCR or RSCR	Combined SNCR/SCR
Control Efficiency	0%	45%	60%	75%
Controlled Emission Rate, lb/MMBtu	0.76	0.42	0.30	0.23
Total Boiler Heat Input, MMBtu/hr	500	500	500	500
Total System Capacity Factor	--	87%	87%	87%
Actual NOx Emissions, ton/yr	1,653	909	661	500
Total Capital Requirement, $	$0	$3,713,500	$10,602,900	$13,497,553
Annual Capital Cost, $/yr		$392,400	$1,120,420	$1,426,300
Annual O&M Cost, $/yr		$275,820	$1,691,250	$1,660,275
Annual NOx Reduction, ton/yr		654	872	1,014
Cost Per Ton NOx Reduced, $/ton		$1,020	$3,225	$3,045
Incremental Annual Cost, $/yr			$2,143,450	$2,418,340
Incremental NOx Reduction, ton/yr			218	142
Incremental Cost Per Ton NOx Reduced, $/ton			$9,840	$17,060

2.8.3.5 Establish BACT

The use of a tail gas SCR can achieve NOx emission rates of 0.30 lb/MMBtu for this biomass-fired boiler. The SCR system could reduce NOx emissions by 992 tons per year (from 1,653 to 661 tons per year). However, the use of SCR would have other adverse environmental, energy, and economic impacts.

At an average cost of $1,020 per ton of NOx removed when an SNCR is utilized, compared to the incremental average cost of $9,840 ton per increased NOx removal with an SCR, tail gas SCR is not an economically feasible control technology for this biomass-fired boiler. SNCR is therefore BACT for the biomass-fired boiler.

Upon construction of the biomass-fired boilers, confirmation testing of the flue gas will be performed to optimize the control of NOx taking into account the ammonia slip. See Section 2.14.3 of this BACT analysis, *Environmental Considerations*, for additional discussion on the importance of minimizing the ammonia slip from the flue gas. The proposed BACT limit is based on the assumed ammonia slip optimization resulting in not more than 25 ppmv NH_3 slip from the boilers and a consistently achievable lb/MMBtu emission limit. Table 2-14 lists the NOx proposed BACT limits. This proposed limit applies during start-up and planned shutdown.

Table 2–14
Biomass-Fired Boiler NOx Proposed BACT Limits

Stack ID	Equipment/ Process	NOx Emission Rate	NOx Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-20001	Biomass-Fired Stoker Boiler	207.56 lb/hr	0.415 lb/MMBtu (24-hour avg) 207.56 lb/hr (Maximum 1-hour)	SNCR with OFA and GCP

ABBK proposes that the final NOx BACT emission limits be either the above proposed limits or the emission rate from initial performance test, if the

result is less than the limits proposed above and provided the performance test result is consistently achievable.

2.8.3.6 *BACT Compliance*

ABBK proposes that the pound per hour limit be considered BACT for the maximum 1-hour limit to ensure compliance with the 1-hour National Ambient Air Quality Standard (NAAQS). The proposed 1-hour BACT limit in pounds per hour would apply during all times, including during start-up and planned shutdown. The proposed BACT limit in lb/MMBtu would apply at all times, including during start-up and planned shutdown, and is based on a 30-day rolling average compliance period.

During start-up, the SNCR system does not work immediately and can only be operational once operating temperatures have been attained (approximately 4 to 6 hours after start-up). When the SNCR manufacturer's minimum operating temperature requirement is met, the SNCR system will be activated for NOx control. During normal operation, the SCNR control system will automatically adjust the ammonia injection rate and zones to meet the specified NOx standard based on the injection rate, boiler load, furnace temperature, and NOx emissions. During shutdown, the SNCR system will remain operational until the operating temperature drops below the minimum requirement.

A 30-day rolling average could absorb the higher emissions during this period. This limit is consistent with the averaging time used by the NSPS that applies to boiler.

ABBK will install, calibrate, and maintain a continuous emissions monitoring system (CEMS) to measure and record the concentration of NOx from the biomass-fired boiler in order to demonstrate compliance with the NOx emission limits.

2.8.4 SO_2 BACT Review

Emissions of sulfur oxides from boiler results from the oxidation of sulfur present in the fuel. Sulfur oxides formed during combustion are primarily SO_2, with minor

amounts of SO_3 and gaseous sulfates. These sulfur compounds form as the sulfur contained in the fuel is oxidized during the combustion process. Uncontrolled sulfur oxide emissions from biomass-fired boiler vary directly with the sulfur content.

2.8.4.1 *Identify Available Control Options*

The following control options have been identified and considered in determining BACT:

- Wet Flue Gas Desulfurization (FGD); and
- Dry FGD.

2.8.4.2 *Eliminate Technically Infeasible Control Options*

"Scrubber" is a general term that describes an air pollution control device or system that uses absorption, both physical and chemical, to remove pollutants from the process gas stream. Scrubber systems rely on a chemical reaction with a sorbent to remove a wide range of pollutants, including acid gases, SO_2, fine particulates and heavy metals (i.e., mercury) from flue gases. When used to remove or "scrub" SO_2 from the flue gas, these devices are commonly called FGD systems. FGD systems are generally classified as either "wet" or "dry". Wet scrubbers have been applied on combustion units firing coal and oil ranging in size from 50 MMBtu/hr to 15,000 MMBtu/hr. Dry and spray dryer scrubbers are generally applied to units less than 3,000 MMBtu/hr.

In a wet FGD system, a liquid sorbent slurry is sprayed into the flue gas in an absorber vessel or spray tower. The gas phase or particulate pollutant comes into direct contact with the sorbent liquid and is dissolved or diffused (scrubbed) into the liquid. The liquid interface for gas and particle absorption include liquid sheets, wetted walls, bubbles and droplets. In the wet processes, a wet slurry waste or by-product is produced. Spent slurry from the reaction is generally disposed of, or when oxidized, results in a gypsum by-product that can be sold. Most wet FGD systems use alkaline slurries of limestone or slaked lime as sorbents; however, sodium-based reagents (sodium bicarbonate or naturally occurring sodium carbonate/sodium bicarbonate minerals, like Trona (trisodium

hydrogendicarbonate dehydrate)) are also used. Sulfur oxides react with the sorbent to form solid salts.

Scrubber technologies for wet scrubbing of gaseous pollutants can achieve extremely high levels of multi-pollutant control from utility and industrial coal-fired boilers, waste-to-energy systems, and other industrial processes. New wet scrubbers routinely achieve SO_2 removal efficiencies of 90% to 95%, with some scrubbers achieving removal efficiencies of up to 98%.

In a dry FGD process, particles of an alkaline sorbent are injected into a flue gas, producing a dry solid by-product. In dry FGD scrubbing, the flue gas leaving the absorber is not saturated (the major distinction between wet and dry scrubbers). Dry scrubbers systems can be grouped into two categories: spray dryers and dry injection systems.

A spray dryer (or semi-dry scrubber) uses much smaller amounts of liquid than a wet FGD system. With a spray dryer absorber (SDA) system, the flue gases enter an absorbing tower (dryer) where hot gases are contacted with a finely atomized slurry. Various calcium and sodium-based reagents can be utilized as the sorbent. SO_2 is absorbed by the sorbent slurry mixture and react to form solid salts. The heat of the flue gas evaporates the water droplets in the sprayed slurry, and a non-saturated flue gas exits the absorber tower where it is then routed to a particulate control device such as an ESP or fabric filter. The waste product can be disposed of, sold as a by-product or recycled to the slurry. Spray dryers commonly are designed for SO_2 removal efficiencies of 80% to 90%.

Dry injection systems involve the injection of a dry sorbent (normally lime or limestone) into the flue gas in the upper reaches of the boiler, or in the ductwork following the boiler. Sulfur oxides react directly with the dry sorbent, which are collected in a downstream particulate control device. Dry scrubbers have significantly lower capital and annual costs than wet systems because they are simpler, demand less water and waste disposal is less complex. Newer applications of dry sorbent injection on small coal-

fired industrial boilers have achieved greater than 90% SO_2 control efficiencies.

Scrubbers have been used in the EPA Acid Rain Program on coal-fired boilers, which are significant sources of hydrochloric acid (HCl) and hydrofluoric acid (HF). According to the EPA and others, both wet and dry scrubbers have been shown to reduce HCl emissions by 95% and more, and wet scrubbers have been shown to reduce HF emissions by more than one-third.

2.8.4.3 *Rank Technically Feasible Control Options*

Control Technology	Reduction Efficiency
Wet FGD	90% to 95%
Dry FGD	80% to 90%

The highest removal efficiencies are theoretically achieved by wet scrubbers. However, newer dry scrubber designs are capable of higher control efficiencies, on the order of 90%. Because of the additional acid gases and air toxics to be controlled in the boiler exhaust, a dry FGD system is recommended by the boiler vendor as part of the combined SDA and fabric filter baghouse control train. A wet FGD is generally applied units larger than the proposed biomass-fired boilers, and offer no significant benefit over dry FGD; therefore, no further analysis will be performed for a wet FGD system. The addition of a baghouse following the dry scrubber system improves SO_2 and chloride capture (estimated to be 90% and 99%, respectively) as it provides additional residence time. The partially reacted sorbent sticks to the filter and builds a layer to capture additional pollutants, called "filter cake".

The top performing technically feasible SO_2 control identified for further evaluation as part of this BACT analysis is a dry FGD system, specifically a SDA utilizing hydrated lime.

2.8.4.4 Evaluate Technically Feasible Control Options

EPA's RBLC database was reviewed to identify technologies used to control SO_2 emissions from biomass-fired boilers with heat inputs greater than 250 MMBtu/hr. No facilities in the RBLC database burn the same types of fuels as ABBK. Most biomass boilers in the database burn various types of wood/wood waste in conjunction with other fuels, including coal, natural gas, fuel oil, wastewater sludge, tire-derived fuel, railroad ties and other non-municipal wastes or production by-products.

The results of the database search from January 1, 2003 to present are summarized in Table 2-15.

Table 2–15
Biomass-Fired Boilers RBLC Summary for SO_2 Emissions

Facility	RBLC ID	Emission Limit (lb/MMBtu)	Basis	Control	Verified
Laidlaw Berlin Biopower	NH-0018	0.012	BACT	Dry Sorbent Injection System	No
NRG Energy Montville Power	CT-0156	0.025	BACT	Low Sulfur Fuels	Unknown
Lindale Renewable Energy	TX-0553	0.025	BACT	None	Unknown
Aspen Power Lufkin Generating Plant	TX-0555	0.025	BACT	None	Unknown
Yellow Pine Energy Corporation	GA-0132	0.014	BACT	Sorbent Injection	No
Archer Daniels Midland Co. Northern Sun	ND-0022	0.47	BACT	None	Yes
Biomass Energy, South Point Biomass Generating	OH-0307	0.087	State BAT	SDA	No
Sierra Pacific Industries Skagit County Lumber Mill	WA-0327	0.025	BACT	None	Unknown
Inland Paperboard and Packaging Bogalusa Mill	LA-0188	1.54	BACT	Fuel Oil Limit	Unknown
Public Service of New Hampshire Schiller Station	NH-0013	0.02	Other	Sorbent Injection	Yes
U.S. Sugar Corp Clewiston Sugar Mill and Refinery	FL-0257	0.06	BACT	Fuel Limit	No

EPA's RBLC database lists 11 SO_2 limitations for biomass-fired boilers with heat inputs greater than 250 MMBtu/hr permitted after January 1, 2003

(see Table 2-11 for the biomass-fired boilers reviewed). The RBLC database indicates a wide range of SO_2 control as BACT, including no control, fuel sulfur content limit, sorbent injection alone, and wet and dry FGD. The BACT emission rates range from 0.012 to 1.54 lb/MMBtu. The lowest demonstrated SO_2 emission rate in the RBLC database is for Schiller Station (0.02 lb/MMBtu, 70% control of SO_2 emissions).

The Schiller Station is a special case, operating a fluidized bed combustor. The facility is permitted to burn wood from whole trees, forest product manufacturing operations, stump grindings and pallets, or bituminous coal. Considering the differences in the sulfur content of wet wood verses the blended biomass fuel at ABBK (estimated to be 0.05% by weight versus 0.98% by weight), it is reasonable to expect the ABBK boiler's SO_2 emissions will be greater.

Schiller Station uses a fabric filter with a SDA (lime injection) system to control particulates, SO_2, sulfuric acid mist and HCl. This SO_2 control system proposed by ABBK is similar to the Schiller Station. The top performing proven control technology identified in the RBLC database is a dry FGD system.

2.8.4.5 *Establish BACT*

Based on best engineering estimates, the proposed biomass-fired boilers with a spray dryer absorber, SDA system can consistently achieve an SO_2 emission rate of 0.21 lb/MMBtu (or 92% SO_2 reduction). Table 2-16 lists the SO_2 proposed BACT limits.

Table 2–16
Biomass-Fired Boiler SO_2 Proposed BACT Limits

Stack ID	Equipment/ Process	SO_2 Emission Rate	SO_2 Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-20001	Biomass-Fired Stoker Boiler	106.16 lb/hr	0.21 lb/MMBtu (24-hour avg) 106.16 lb/hr (Maximum 1-hour)	Spray Dry Absorber (SDA)

ABBK proposes that the final SO_2 BACT emission limits be either the above proposed limits or the emission rate from initial performance test, if the result is less than the limits proposed above and provided the performance test result is consistently achievable.

2.8.4.6 BACT Compliance

ABBK proposes that the pound per hour limit be considered BACT for the maximum 1-hour limit to ensure compliance with the 1-hour National Ambient Air Quality Standard (NAAQS). The proposed 1-hour BACT limit in pounds per hour would apply during all times, including during start-up and planned shutdown. The proposed BACT limit in lb/MMBtu would apply at all times, including during start-up and planned shutdown, and is based on a 30-day rolling average compliance period.

During start-up, SO_2 is minimized through the use of low sulfur fuels (i.e., natural gas) and/or the injection of a sorbent into the furnace because the FGD system does not work at optimum design until approximately 4 hours after start-up. A 30-day rolling average could absorb the higher emissions during this period. This limit is consistent with the averaging time used by the NSPS that applies to boiler.

As required in 40 CFR §60.47Db, ABBK will install, calibrate, and maintain a CEMS to measure and record the concentration of SO_2 from this biomass-fired boiler in order to demonstrate compliance with the SO_2 emission limit.

2.8.5 CO BACT Review

Fuel combustion CO emissions result from the incomplete combustion of carbon and organic compounds contained in the fuel. Factors affecting CO emissions include firing temperatures, excess oxygen and residence time in the combustion zone, and combustion area mixing characteristics. An increase in combustion zone residence time and oxygen levels and improved mixing of fuel and combustion air will increase oxidation rates and decrease CO emission rates. The proposed ABBK boiler is designed and operated to minimize the formation of CO

by maximizing the combustion area mixing of the biomass fuel and combustion air.

In general, emissions of NOx and CO are inversely related (i.e., decreasing NOx emissions will result in an increase in CO emissions and vice-versa). Accordingly, boiler combustion controls designed to lower NOx emissions (e.g., lower combustion temperatures) would also be expected to cause a collateral increase in CO emissions. Accordingly, boiler combustion design and operation requires a balancing of the competing goals to minimize the formation of both NOx and CO.

2.8.5.1 *Identify Available Control Options*

The following control options have been identified and considered in determining BACT:

- Good Combustion Practices (GCP); and
- Oxidation Catalysts.

2.8.5.2 *Eliminate Technically Infeasible Control Options*

Optimization of the design, operation, and maintenance of the boiler combustion system is the primary technology available for reducing CO emissions. Good combustion controls involve boiler combustion designs and operating practices that improve the oxidation process and minimize incomplete combustion. Key combustion design and operating parameters include sufficient excess air, high combustion temperatures, adequate residence time, and good mixing of the combustion air and fuel.

Oxidation catalysts have recently been used to reduce CO emissions as a post combustion control system on gas-fired combustion turbines, but not on biomass-fired boilers. Acceptable catalyst operating temperatures range from 400°F to 1,250°F, with the optimum temperature range being 850°F to 1,100°F. Below 600°F, a greater catalyst volume would be required to achieve the same reduction.

The boiler's exhaust temperatures will be below 400°F and flue gas temperatures in the furnace are greater than 1,250°F. As a result, a suitable location within the boilers would be have to be created in order to

provide the proper temperature range and residence time for installation of an oxidation catalyst. Such a location does not exist in the current solid biomass-fired boiler configuration design.

Further, implementation of oxidation catalysts involves a complex technology transfer project that has not been commercially demonstrated on biomass-fired boilers. A catalytic oxidizer offers no performance advantages over the top performing technology, thermal oxidation in the furnace due to good combustion practices. Also, oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies. Oxidation catalysts are also subject to masking and/or binding by fly ash contained in the exhaust stream of a boiler. Given these facts, it was determined unnecessary to evaluate the cost of unproven and potentially infeasible technology that is clearly more expensive than the top performing technology selected for this application.

2.8.5.3 *Rank Technically Feasible Control Options*

Based on the above discussion, the only technically feasible CO control technology identified for further evaluation as part of this BACT analysis is GCP.

2.8.5.4 *Evaluate Technically Feasible Control Options*

EPA's RBLC database was reviewed to identify technologies used to control CO emissions from biomass-fired boilers with heat inputs greater than 250 MMBtu/hr. No facilities in the RBLC database burn the same types of fuels as ABBK. Most biomass boilers in the database burn various types of wood/wood waste in conjunction with other fuels, including coal, natural gas, fuel oil, wastewater sludge, tire-derived fuel, railroad ties and other non-municipal wastes or production by-products.

The results of the database search from January 1, 2003 to present are summarized in Table 2-17.

Table 2–17
Biomass-Fired Boilers RBLC Summary for CO Emissions

Facility	RBLC ID	Emission Limit (lb/MMBtu)	Basis	Control	Verified
Georgia Power Co., Mitchell Steam Generation Plant	GA-0140	0.45	BACT	GCP	Unknown
Laidlaw Berlin Biopower	NH-0018	0.075	BACT	BFB Boiler Design and FGR	Unknown
NRG Energy Montville Power	CT-0156	0.1	BACT	Oxidation Catalyst	No
Lindale Renewable Energy	TX-0553	0.31	BACT	GCP	Unknown
Aspen Power Lufkin Generating Plant	TX-0555	0.075	Other	Oxidation Catalyst	Unknown
Yellow Pine Energy Corporation	GA-0132	0.149	BACT	BFB Boiler Design GCP	Unknown
Simpson Tacoma Kraft	WA-0335	0.35	BACT	OFA	Unknown
Archer Daniels Midland Co. Northern Sun	ND-0022	0.63	BACT	GCP	Yes
Biomass Energy, South Point Biomass Generating	OH-0307	0.1	BACT	Oxidation Catalyst	No
Boise Cascade Corp, Wallula	WA-0337	500 ppmvd	BACT	OFA	Unknown
Sierra Pacific Industries Skagit County Lumber Mill	WA-0327	0.35	BACT	None	Unknown
Darrington Energy Cogeneration Power Plant	WA-0329	0.35	BACT	GCP	Unknown
Inland Paperboard and Packaging Bogalusa Mill	LA-0188	0.6	BACT	OFA, GCP	Unknown
Public Service of New Hampshire Schiller Station	NH-0013	0.1	BACT	GCP	Yes
Inland Paperboard and Packaging, Rome Linerboard Mill	GA-0114	368 ppm @ 3% O_2	BACT	GCP	Yes
U.S. Sugar Corp Clewiston Sugar Mill and Refinery	FL-0257	0.38	Other	GCP	No

EPA's RBLC database lists 16 CO limitations for biomass-fired boilers with heat inputs greater than 250 MMBtu/hr permitted after January 1, 2003 (see Table 2-11 for the biomass-fired boilers reviewed). The BACT emission rates range from 0.075 to 0.63 lb/MMBtu. The lowest demonstrated CO emission rate in the RBLC database is for Schiller Station (0.10 lb/MMBtu).

The top performing proven control technology identified in the RBLC database is GCP.

The Schiller Station is a special case, operating a fluidized bed combustor. The facility is permitted to burn wood from whole trees, forest product manufacturing operations, stump grindings and pallets, or bituminous coal. Considering the differences in the fuel nitrogen content of wet wood verses the blended biomass fuel at ABBK (estimated to be 0.22% by weight versus 1.54% by weight), it is reasonable to expect the ABBK boiler's CO emissions will be greater. The design of the boiler will be intended to simultaneously minimize the formation of both NOx and CO emissions; therefore, the design features that minimize CO emissions are interrelated with the boiler optimization used to minimize NOx formation prior to the application of the SNCR system.

2.8.5.5 *Establish BACT*

Based on best engineering estimates, the proposed biomass-fired boiler with GCP can consistently achieve a CO emission rate of 0.22 lb/MMBtu. Table 2-21 lists the CO proposed BACT limits.

Table 2–18
Biomass-Fired Boiler CO Proposed BACT Limits

Stack ID	Equipment/ Process	CO Emission Rate	CO Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-20001	Biomass-Fired Stoker Boiler	110.04 lb/hr	260 ppmv@3%O_2	GCP

ABBK proposes that the final CO BACT emission limit be either the above proposed limit or the emission rate from initial performance test, if the result is less than the limit proposed above and provided the performance test result is consistently achievable.

2.8.5.6 *BACT Compliance*

ABBK proposes that the CO concentration in the flue gas be considered BACT and used for compliance purposes for the biomass-fired boiler. The

proposed BACT limit in applies during all times, including during SSM, and is based on a 30-day rolling average compliance period.

2.8.6 PM/PM_{10}/$PM_{2.5}$ BACT Review

2.8.6.1 Identify Available Control Options

The following control options have been identified and considered in determining BACT:

- Fabric Filter Baghouse;
- Wet ESPs; and
- Dry ESPs.

2.8.6.2 Eliminate Technically Infeasible Control Options

Fabric filtration in a baghouse consists of a number of filtering bags that are suspended in a housing. Particulate laden gases pass through the housing and collect on the fabric of the filter bag. Fabric filters are generally considered unacceptable for the control of biomass combustion due to the danger of fires unless there is some acid gas control preceding the fabric filter. Because acid gas control in the form of a dry (sorbent injection) scrubber will be utilized, fabric filtration is technically feasible. However, fabric filtration is not technically feasible for condensable particulate matter that is in a vapor form at stack conditions, and thus is not intercepted by the fabric.

ESPs remove particulate matter from the flue gas stream using the principle of electrostatic attraction. Particulate matter is charged with a high direct current voltage and subsequently attracted to oppositely charge collection plates. Wet ESPs operate using the same principles as standard ESPs, but the final cleaning step of the collection plates utilizes water. Wet and dry ESP systems are technically feasible for the proposed boiler system. However, ESPs are not technically feasible for condensable particulate matter that is in a vapor form at stack conditions, and thus not significantly affected by the electric current.

2.8.6.3 *Rank Technically Feasible Control Options*

Control Technology	Reduction Efficiency
Baghouse	99+%
Dry ESP	99+%
Wet ESP	99+%

A baghouse, dry ESP and wet ESP are all capable of achieving filterable PM/PM_{10} emissions reductions of 99% or more. A fabric filter baghouse is preferred for the ABBK boilers as the addition of a baghouse following the dry (sorbent injection) scrubber system improves SO_2 and chloride capture (estimated to be 90% and 99%, respectively) as it provides additional residence time. The partially reacted sorbent sticks to the filter and builds a layer to capture additional pollutants.

Further, a wet or dry ESP offer no performance or cost advantages over a baghouse; therefore, no further analysis will be performed for ESPs. The top performing technically feasible PM/PM_{10} control technology identified for further evaluation as part of this BACT analysis is a fabric filter baghouse.

2.8.6.4 *Evaluate Technically Feasible Control Option*

EPA's RBLC database was reviewed to identify technologies used to control PM/PM_{10} emissions from biomass-fired boilers with heat inputs greater than 250 MMBtu/hr. No facilities in the RBLC database burn the same types of fuels as ABBK. Most biomass boilers in the database burn various types of wood/wood waste in conjunction with other fuels, including coal, natural gas, fuel oil, wastewater sludge, tire-derived fuel, railroad ties and other non-municipal wastes or production by-products.

The results of the database search from January 1, 2003 to present are summarized in Table 2-19.

Table 2–19
Biomass-Fired Boilers RBLC Summary for PM/PM_{10} Emissions

Facility	RBLC ID	Emission Limit (lb/MMBtu)	Basis	Control	Verified
Georgia Power Co., Mitchell Steam Generation Plant	GA-0140	0.04 (PM10, filterable)	BACT	ESP, Cyclone	Unknown
Laidlaw Berlin Biopower	NH-0018	0.01 (PM10, filterable & PM2.5, filterable)	BACT	Fabric Filter Baghouse	No
NRG Energy Montville Power	CT-0156	0.026 (PM, total)	BACT	Dry ESP and Cyclones	No
Lindale Renewable Energy	TX-0553	0.02 (PM, filterable)	BACT	ESP	Unknown
Aspen Power Lufkin Generating Plant	TX-0555	0.012 (PM, filterable) 0.025 (PM, total)	MACT BACT	ESP	Unknown
Yellow Pine Energy Corporation	GA-0132	0.01 (PM10, filterable) 0.018 (PM10, total)	BACT	Fabric Filter Baghouse	No
Koda Energy	MN-0074	0.037	BACT	ESP, Cyclone	Unknown
Simpson Tacoma Kraft	WA-0335	0.02 (PM10, filterable)	BACT	ESP	Yes
Archer Daniels Midland Co. Northern Sun	ND-0022	0.08	BACT	ESP	Yes
Biomass Energy, South Point Biomass Generating	OH-0307	0.0064 (PM, filterable)	BACT	Fabric Filter Baghouse	No
Sierra Pacific Industries Skagit County Lumber Mill	WA-0327	0.02 (PM10, filterable)	BACT	ESP	Unknown
Darrington Energy Cogeneration Power Plant	WA-0329	0.02 (PM10, filterable)	BACT	ESP	Unknown
Inland Paperboard and Packaging Bogalusa Mill	LA-0188	0.15 (PM10, filterable)	BACT	Wet Scrubber	Unknown
Public Service of New Hampshire Schiller Station	NH-0013	0.025 (PM10, filterable)	MACT	Fabric Filter Baghouse	Yes
Inland Paperboard and Packaging, Rome Linerboard Mill	GA-0114	0.025 (PM10, filterable)	BACT	ESP	Yes
U.S. Sugar Corp Clewiston Sugar Mill and Refinery	FL-0257	0.026	BACT	ESP, Cyclone	No

EPA's RBLC database lists 16 PM/PM_{10} limitations for biomass-fired boilers with heat inputs greater than 250 MMBtu/hr permitted after

January 1, 2003 (see Table 2-11 for the biomass-fired boilers reviewed). The RBLC database indicates a wide range of PM/PM_{10} control as BACT, including fabric filtration, wet scrubbing, ESP and ESP in combination with a cyclone, fabric filter or scrubber. The PM_{10} BACT emission rates range from 0.0064 to 0.15 lb/MMBtu. The lowest demonstrated PM/PM_{10} emission rate in the RBLC database is for Sierra Tacoma Kraft (0.02 lb/MMBtu) when an ESP was used and Schiller Station (0.025 lb/MMBtu) when a fabric filter baghouse was used.

In the case of the Schiller Station, an SDA is utilized for SO2 control and the fabric filter is an integral part of the acid gas control system as the filter cake aids in acid gas control. This is the same control system proposed by ABBK.

Considering the differences in the ash content of wet wood verses the blended biomass fuel at ABBK (estimated to be 1% by weight versus 13% by weight), it is reasonable to expect the ABBK boiler's PM emissions will be greater. The implementation of a fabric filter baghouse will achieve a maximum filterable PM_{10} emission rate of at the facility of 0.013 lb/MMBtu. This emission rate is consistent with other established BACT limits for wood-fired boilers, as detailed in the RBLC database review. The overall filterable PM/PM_{10} control will be based on a 99.8% control efficiency due to the dual control technology design for HCl control.

In the case of condensable PM, there was no information in the RBLC database regarding emission controls or BACT limits. Emissions of condensable PM were estimated using EPA AP-42. A fabric filter baghouse is expected to have the greatest potential to reduce both filterable and condensable particulate matter emissions from the biomass-fired boiler due to the control train design for maximum acid gas control.

2.8.6.5 *Establish BACT*

The implementation of a fabric filter baghouse will achieve a filterable $PM/PM_{10}/PM_{2.5}$ control efficiency of 99+%. Based on best engineering estimates, the proposed biomass-fired boiler with a baghouse can

consistently achieve a filterable PM emission rate of 0.015 lb/MMBtu; a filterable PM_{10} emission rate of 0.013 lb/MMBtu; and a filterable $PM_{2.5}$ emission rate of 0.011 lb/MMBtu.

Table 2-20 lists the proposed filterable PM BACT limits.

Table 2–20
Biomass-Fired Boilers Filterable PM Proposed BACT Limits

Stack ID	Equipment/ Process	Filterable PM Emission Rate	Filterable PM Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-20001	Biomass-Fired Stoker Boiler	PM: 7.27 lb/hr PM_{10}: 6.49 lb/hr $PM_{2.5}$: 5.58 lb/hr	PM: 0.015 lb/MMBtu PM_{10}: 0.013 lb/MMBtu $PM_{2.5}$: 0.011 lb/MMBtu	Fabric Filter Baghouse

ABBK proposes that the final filterable and condensable PM BACT emission limits be either the above proposed limits or the emission rate from initial performance test, if the result is less than the limits proposed above and provided the performance test result is consistently achievable.

The biomass-fired stoker boiler is exempt from §60.43b and is subject to the more stringent limit established in 40 CFR Part 63, Subpart JJJJJJ, *National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers*. ABBK will comply with the fabric filter control requirements specified in 40 CFR Part 63, Subpart JJJJJJ, Table 3, *Operating Limits for Boilers with Emission Limits.*

2.8.6.6 *BACT Compliance*

ABBK proposes to use the fabric filter baghouse as part of the acid gas control system, specifically HCl control. KDHE has indicated that they are reviewing the potential monitoring requirements for both PM and HCl. ABBK has proposed a continual compliance testing and monitoring program for the boiler which did not include a PM CEMS. Recent conversations with KDHE indicate that this may be required. The minimum requirement under 40 CFR Part 63, Subpart JJJJJJ is the installation of a bag leak detection system and compliance with a 20%

opacity limit per K.A.R. 28-19-650. At this time, no further monitoring in addition to performance testing is proposed for the biomass-fired boiler.

2.9 Cooling Water Tower

2.9.1 Source Description

The production process will be cooled by circulating water through heat exchangers, a chiller, and the cooling water tower. The cooling tower is an essential utility in the ethanol production and refining process. At the cogeneration plant, exhaust steam is condensed under vacuum against cooling water in the cooling water tower. Enzymatic hydrolysis process steam is extracted from the turbines at a lower pressure from uncontrolled extraction ports. Boiler feedwater preheated steam is also extracted from the turbines from uncontrolled extraction ports. The cooling water tower (EP-04001) will contain three (3) cells, with a total water circulation rate of 43,200 gallons per minute. The cooling water tower will be equipped with a drift (mist) eliminator.

Cooling towers are a source of particulate matter emissions due to the loss or drift of droplets of cooling water containing dissolved solids from the tower. The particulate emissions are assumed all condensable, and therefore all assumed to be less than 1.0 micrometer in diameter. The water generated from the cooling towers will not come into contact with the production processes, thus no VOC emissions are expected.

Major emission constituents are particulate matter, salts, and any other chemicals that may either are present in the stream being cooled or that may be added to the circulating water. The visible emissions mainly consist of water vapor. The cooling water tower emissions were calculated using AP-42, Section 13.4, *Wet Cooling Towers*, Final Section, January 1995, and vendor engineering data.

2.9.2 PM/PM_{10} BACT Review

2.9.2.1 Identify Available Control Options

The following control options have been identified and considered in determining BACT:

- Drift Eliminators;

- Total Dissolved Solids (TDS) Limit;
- TDS Removal System; and
- Combination of these control options.

2.9.2.2 *Eliminate Technically Infeasible Control Options*

Drift elimination is the removal of entrained liquid droplets from a vapor stream. The installation of high efficiency drift eliminators and the use of water treatment technology to further reduce TDS in the cooling water are considered feasible control technologies. The only feasible TDS removal technology identified was demineralization using softeners and ion exchange beds to remove additional TDS from the cooling water makeup stream. Both reverse osmosis and distillation are rejected as TDS reducing options due to their high energy requirements and high annual operating costs relative to ion exchange based on demineralization. Demineralization is not considered technically feasible and was not evaluated in this analysis, as the substantial additional cost of treating and/or disposing of by-product sludge, spent resin and wastewater generated by the demineralization process are cost prohibitive and this technology has not been implemented at similar facilities.

2.9.2.3 *Rank Technically Feasible Options*

The use of a drift eliminator is the most technically feasible control technology. A TDS limit for the circulating water is usually viewed as a measure that benefits air quality by reducing the dissolved salts that can be precipitated from drift aerosols. To reduce TDS, the facility must introduce a higher volume flow of make-up water to the tower. This has the potential disadvantage of increasing the overall plant water requirements.

2.9.2.4 *Evaluate Technically Feasible Control Options*

EPA's RBLC database was reviewed to identify $PM/PM_{10}/PM_{2.5}$ control technologies that were potentially applicable to cooling towers, including a review of cooling towers located at similar facilities and cooling towers

permitted within the past three years. The results of the database search are summarized in Table 2-21.

Table 2–21
Cooling Water Towers RBLC Summary for $PM/PM_{10}/PM_{2.5}$ Emissions

Facility	RBLC ID	Permit Date	BACT Limit	Control
Dow Chemical Company Plaquemine Cogeneration	LA-0136	07/23/08	0.005%	Good Operating Practices
Florida Power and Light Company	FL-0303	07/30/08	0.0005%	Drift Eliminator
Florida Municipal Power Agency	FL-0304	09/08/08	0.0005%	Drift Eliminator
Southwest Electric Power Company	AR-0094	11/05/08	0.0005%	Drift Eliminator
Competitive Power Ventures	MD-0040	11/12/08	0.0005%	Drift Eliminator
ConocoPhillips Company Billings Refinery	MT-0030	11/19/08	0.0005%	Drift Eliminator
Ohio Clean River Clean Fuels	OH-0317	11/20/08	0.0005%	Drift Eliminator
Southeast Idaho Energy Power County Advanced Energy Center	ID-0017	02/10/09	0.0005% 5000 ppm TDS	Drift Eliminator

The most effective, technically feasible option identified for control of mist/drift from the cooling water towers is the use of a drift eliminator. Drift eliminators designed for drift loss factors ranging from 0.005% to 0.0005% have been established as BACT at similar facilities and for cooling towers permitted within the past two years. Facilities that have lower drift rates (0.0001% and 0.0002%) listed in the RBLC database have been permitted in past years, but those lower rates are considered more stringent than BACT.

2.9.2.5 *Establish BACT*

According to EPA's RBLC database, the use of a drift eliminator designed for a 0.0005% drift with TDS limit is ranked as the top performing control technology and has been established as BACT for cooling towers used at power facilities permitted in the last two years. ABBK proposes the BACT for the cooling towers be the specification and installation of high efficiency drift eliminators designed for no more than 0.0005% drift combined with a TDS limit. This drift rate was provided by the vendor as the basis for the current proposed cooling water towers design.

Table 2-22 lists the PM/PM_{10} proposed BACT limits.

Table 2–22
Cooling Water Tower $PM/PM_{10}/PM_{2.5}$ Proposed BACT Limits

Stack ID	Equipment/ Process	PM/PM_{10} Emission Rate	PM/PM_{10} Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-04001	Cooling Water Tower	PM: 0.17 lb/hr PM_{10}: 0.12 lb/hr $PM_{2.5}$: 0.07 lb/hr	1,575 ppm TDS	Drift Eliminator with 0.0005% Drift Rate

2.9.2.6 *BACT Compliance*

ABBK proposes the use of the top performing control technology, drift eliminators, to control $PM/PM_{10}/PM_{2.5}$ emissions from the cooling water towers. ABBK also proposes the use of a TDS concentration limit, which is a measureable limit that will be used to demonstrate compliance. The TDS concentration to be used for compliance will be based on a 24-hour average concentration. No other emission limits are proposed. ABBK will also provide a copy of the tower construction specifications, maintenance and recordkeeping documents to KDHE upon request to demonstrate compliance with BACT.

2.10 Biogas Flare BACT Analysis

2.10.1 Source Emissions

The facility design will incorporate a flare (EP-09001) for control of process vents flow, biogas and product loadout vapors. The vent streams will normally be vented to the biomass-fired boiler for combustion; however biogas may be vented to the flare as needed for up to 3,960 hours per year.

2.10.2 $PM/PM_{10}/PM_{2.5}$, NOx, CO, and SO_2 BACT Review

2.10.2.1 *Identify Available Control Options*

The following control options have been identified and considered in determining BACT:

- Flare; and
- Fuel Gas in Other Facility Processes.

2.10.2.2 Eliminate Technically Infeasible Control Options

There are no other combustion sources at the facility except for the biomass-fire boiler. Flaring is the only technically feasible option available when the vent streams cannot be vented to the boiler.

2.10.2.3 Evaluate Feasible Control Options

Flares can be used to control almost any hydrocarbon laden streams and can handle fluctuations in hydrocarbon concentrations, flow rate, heat content, and inert content, provided that the gas has a heating value greater than 300 Btu/scf.

Flaring is appropriate for continuous, batch and variable flow vent stream application. Some streams, such as those containing halogenated or sulfur-containing compounds, are usually not flared because they corrode the flare tip or cause formation of secondary pollutants (such as acid gases or sulfur dioxide). A flare normally provides a VOC destruction efficiency of greater than 98% and is considered technically feasible. Because flares are primarily safety devices which deal with flows of short durations (generally an upset condition or an accidental release from a process) rather than a control device which treats a continuous waste stream, it is not entirely appropriate to compare the cost effectiveness of flares to other control devices. Cost per ton of pollutant controlled largely depends upon the annual hours of operation.

Emissions from flaring include carbon particles (soot), unburned hydrocarbons, CO, and other partially burned and altered hydrocarbons. Also emitted are NOx and, if sulfur-containing materials are flared, SO_2. The quantities of hydrocarbon emissions generated relate to the degree of combustion. The degree of combustion depends largely on the rate and extent of fuel-air mixing and on the flame temperatures achieved and maintained.

Properly operated flares achieve at least 98% combustion efficiency in the flare plume, meaning that hydrocarbon and CO emissions amount to less than 2% of hydrocarbons in the exhaust gas stream. The tendency of a

fuel to smoke or make soot is influenced by fuel characteristics and by the amount and distribution of oxygen in the combustion zone. For complete combustion, at least the stoichiometric amount of oxygen must be provided in the combustion zone. Complete combustion to reduce soot requires sufficient combustion air and proper mixing of air and waste gas.

EPA's RBLC database was reviewed to identify other potential control technologies that were potentially applicable to SSM flares. The results of the database search are summarized in Table 2-23.

Table 2–23
Biomass-Fired Boilers RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Limit	Control
Valero Refining St. Charles Refinery	ARU Flare	LA-0213	11/17/09	None	NSPS Subpart A; fuel sulfur limit
Ridgewood Power Management	ULE Flare (20.8 MMBtu/hr)	RI-0023	05/12/09	NOx: 0.025 (LAER) CO: 0.06	None
Southeast Idaho Energy	Process Flare	ID-0017	02/10/09	PM_{10}: Smokeless CO/NOx: GCP	NSPS Subpart A
Homeland Energy Solutions	Startup and Shutdown Flares 1, 2 and 3 and EP33A, EP33B, and EP33C (25 MMBtu/hr)	IA-0089	08/08/07	PM/PM_{10}: 0.0076 NO_x: 0.20 SO_2: 0.395 CO: 1.1	Hours of operations limitation (146 hours per rolling 12-month period)
Homeland Energy Solutions	Biomethanator Flare, Methane, Natural Gas, Syngas (6.4 MMBtu/hr)[1]	IA-0089	08/08/07	PM/PM_{10}: 0.0019 NO_x: 0.07 SO_2: 0.0007 CO: 0.37	None
Tesoro Alaska Company, Kenai Refinery	#1 Reheater Startup Burner, Natural Gas, Refinery Gas, and Liquid Petroleum Gas (1.65 MMBtu/hr)	AL-0037	03/21/00	PM/PM_{10}: 0.005 NO_x: 0.14 SO_2: None CO: 0.035	Fuel sulfur limit[2]
Tesoro Alaska Company, Kenai Refinery	#1 Reheater Startup Burner, Natural Gas, Refinery Gas, and Liquid Petroleum Gas (1.15 MMBtu/hr)	AL-0037	03/21/00	PM/PM_{10}: 0.005 NO_x: 0.14 SO_2: None CO: 0.035	Fuel sulfur limit[2]

Table 2–23
Biomass-Fired Boilers RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Limit	Control
Tesoro Alaska Company, Kenai Refinery	#3 Reheater Startup Burner, Natural Gas, Refinery Gas, and Liquid Petroleum Gas (1.05 MMBtu/hr)	AL-0037	03/21/00	PM/PM_{10}: 0.005 NO_x: 0.14 SO_2: None CO: 0.035	Fuel sulfur limit[2]
Tesoro Alaska Company, Kenai Refinery	#4 Reheater Startup Burner, Natural Gas, Refinery Gas, and Liquid Petroleum Gas (1.9 MMBtu/hr)	AL-0037	03/21/00	PM/PM_{10}: 0.005 NO_x: 0.14 SO_2: None CO: 0.035	Fuel sulfur limit[2]
Louisiana Pacific Corp.	Burner Shat-up/Shutdown, Natural Gas (30 MMBtu/hr)	AL-0221	06/14/06	PM/PM_{10}: 0.0075 NO_x: 0.049 SO_2: 0.006 CO: 0.0824	Low NO_x burner and good design/ operation
Biorecycling Technologies	Flare Assembly, Biogas, Natural Gas pilot (10.9 MMBtu/hr)	CA-0824	01/20/98	PM/PM_{10}: 0.03 NO_x: 0.06 SO_2: None CO: None	None

Note 1: Emission limit is a prorated concentration of 230 mg H_2S/dscf, and 500 ppm SO_2 averaged over 3 hours. Fuel sulfur content limit is 0.35% S_2 for Diesel, 0.01% S_2 for Natural Gas, 0.01% S_2 for Liquid Petroleum, and 168 ppmv H_2S for Refinery Gas.
Note 2: BACT for NOx, and CO based on AP-42, Section 13.5 emission factors for industrial flares.

For the flares detailed in Table 2-23, the BACT control technologies included low NOx burners, fuel sulfur content limits, and good combustion practices.

2.10.2.4 Establish BACT

There are no known technically feasible control options available in addition to flaring. The BACT limits presented in Section 2.8 of this BACT analysis include those emissions from the vent streams that can be flared. ABBK proposes that the BACT limits for the flare consist of the following:

- Hours of operations limit to 3,960 hours per year;
- Limit pilot fuel to natural gas;
- Smokeless design;
- Treatment of biogas to remove sulfur to ≤100 ppm;
- Use of low NOx burner; and
- Good combustion practices.

2.10.2.5 BACT Compliance

ABBK proposes the use of the top performing control technology, flaring, for control of process vents flow, biogas and product loadout vapors w hen the vent streams cannot be vented to the boiler. ABBK will meet the requirements for flares that are contained in NSPS Subpart A. The biogas will be tested to confirm the sulfur content. ABBK will also provide a copy of the flare construction specifications, maintenance, and all required NSPS Subpart A reporting and recordkeeping documents to KDHE upon request to demonstrate compliance with BACT.

2.11 Firewater Pump Engine

2.11.1 Source Emissions

One 460 horsepower (Hp) (343 kilowatt (kW)) firewater pump engine will be installed at the facility to protect personnel and equipment in the event of a fire. The firewater pump engine will combust diesel fuel and meet the New Source Performance Standard (NSPS) regulation, 40 CFR Part 60, Subpart IIII, *Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICEs)*. The emergency engine is assumed to operate less than 100 hours per year for maintenance checks and readiness testing to qualify as emergency engines under NSPS Subpart IIII (40 CFR §60.4211(e)).

For this emergency engine, ABBK has determined that the requirements of NSPS Subpart IIII, which regulate manufacturers and operators of CI ICEs, are the appropriate basis for determining BACT. These standards phase in over time for specific engine Hp ratings and use categories, and the standards represent a near-term driver for emissions reductions from new emergency use diesel fuel-fired CI engines.

For emergency engines with a maximum engine power greater than 50 Hp, the manufacturer must certify, pursuant to 40 CFR §60.4202(a)(2), that the engine meets the NSPS standards for new non-road compression ignition engines for the same model year and maximum power listed in 40 CFR §89.112. It is assumed that the model to be chosen for this facility will be a 2011 model. The NSPS Subpart IIII does not have individual limits for NOx or VOC. Instead the limit is applicable to

the sum of the two pollutants. Therefore, each pollutant has been estimated at the worst-case (either all NOx or all VOC), while the NSPS limit is applicable to the sum of the NOx and VOC emissions.

All diesel fuel-fired CI engines generally operate in the same basic process. A combustible mixture of air and fuel is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited and the resulting high-pressure products of combustion push the piston down the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated. The products of combustion, which are consequently emitted as exhaust, are primarily NOx, CO and hydrocarbons. Relatively minor quantities of particulate matter (PM and PM_{10}), SO_2 and HAPs are also emitted.

2.11.2 NOx BACT Review

2.11.2.1 *Identify Available Control Options*

NOx formation in ICEs is directly related to high pressures and temperatures during the combustion process and to the nitrogen content, if any, of the fuel. The predominant NOx formation mechanism with ICEs is thermal NOx which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O2) molecules in the combustion air. Most thermal NOx is formed in the high-temperature region of the cylinder from dissociated molecular N2 in the combustion air. Distillate oils have essentially no chemically-bound fuel nitrogen; therefore, fuel NOx is not a source of NOx.

Hydrocarbon emissions are primarily the result of incomplete combustion. Hydrocarbon emissions are created when some of the fuel remains unburned or is only partially burned during the combustion process. Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets; and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the

combustion volume caused by piston motion before combustion is completed.

NOx emission controls for limited use diesel fuel-fired CI engine that have been identified and considered in determining BACT include the following:

- Advanced engine design (per NSPS Subpart IIII) with combustion optimization;
- Exhaust gas recirculation for NOx reduction;
- Lean-NOx catalyst technology;
- NOx adsorber technology;
- Oxidation catalysts;
- Selective catalytic reduction (SCR); and
- Selective non-catalytic reduction (SNCR)

2.11.2.2 Eliminate Technically Infeasible Control Options

Lean-NOx catalyst and NOx adsorber technologies have not been demonstrated to function efficiently on stationary CI engines or on sources with similar exhaust gas characteristics. SCR and SNCR technologies are not technically feasible for limited operation emergency use applications and have not been required for BACT/LAER on such applications.

The emergency diesel fuel-fired engines that will be installed at the facility will meet specific design emission standards that are mandated by the NSPS Subpart IIII regulations, and these specific engine standards are dependent on when the engines are purchased. The NSPS Subpart IIII standard is a mandatory function that ensures certain engine standards are met, and the "feasible" engine design standards will increase with time. It is this NSPS standard that serves as the basis for this BACT determination.

2.11.2.3 Rank Technically Feasible Control Option

Based on the above discussion, the only technically feasible NOx control technology identified for further evaluation as part of this BACT analysis is

advanced engine design with good combustion control (combustion optimization).

2.11.2.4 *Evaluate Technically Feasible Control Options*

EPA's RBLC database was reviewed to identify NOx control technologies that were potentially applicable to limited use diesel fuel-fired engines. The results of the database are summarized in Table 2-24.

Table 2–24
Emergency Diesel Fuel-fired CI Engines RBLC Summary for NOx Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Limit	Control
Ohio River Clean Fuels	Fire Pump Engines (300 Hp)	OH-0317	11/20/08	7.8 g/Hp-hr	NSPS Tier II Certified
Competitive Power Ventures	Emergency Firewater Pump (300 Hp)	MD-0040	11/12/08	3.0 g/Hp-hr	NSPS Tier II Certified; LAER
Tate & Lyle Ingredients Americas	Fire Pump Engine (575 Hp)	IA-0095	09/19/08	3.0 g/Hp-hr	NSPS Tier II Certified

2.11.2.5 *Establish BACT*

Stationary firewater pump engines with a displacement of less than thirty liters per cylinder must comply with the emission standards in Table 4 of NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines(§§60.4200 through §§60.4219). For emergency engines with maximum engine power greater than 50 horsepower (hp) the manufacturer must certify, pursuant to 40 CFR 60.4202(a)(2), that the engine meets the standards for new non-road compression ignition engines for the same model year and maximum power listed in 40 CFR 89.112. It is assumed that the model to be chosen for this facility will be a 2011 or newer model and will meet the Tier 3 standards.

Due to the low rate of emissions from these emergency engines and the availability of engines that are certified to achieve these emission levels, ABBK requests that BACT be established as advanced engine design with good combustion control (combustion optimization), rather than emission limits.

2.11.2.6 BACT Compliance

ABHK proposes to install diesel fuel-fired engines that meet the applicable NSPS diesel Tier 3 emission standards. ABBK will provide a copy of the manufacturer's certification to KDHE upon request to demonstrate compliance with BACT.

2.11.3 SO_2 BACT Review

2.11.3.1 Identify, Eliminate and Rank Available Control Options

SO_2 emissions may be emitted from the diesel fuel-fired CI engines. SO_2 emissions are a function of the sulfur content in the fuel. During the combustion process, the sulfur in the fuel is oxidized to SO_2. The subsequent oxidation of SO_2 to SO_3 and reaction with water produces H_2SO_4.

The only SO_2 control option identified for limited-use engines like the emergency diesel fuel-fired CI engines is the use of ultra low sulfur diesel fuel. Based on the projected availability of diesel fuel that meets EPA mandated fuel sulfur standards, a diesel fuel sulfur content limit of 15 parts per million by weight (ppmw), equivalent to 0.0015% by weight is achievable.

2.11.3.2 Evaluate Technically Feasible Control Options

EPA's RBLC database was reviewed to identify SO_2 control technologies that were potentially applicable to limited use diesel fuel-fired engines. The results of the database are summarized in Table 2-25.

Table 2–25
Emergency Diesel Fuel-fired CI Engines RBLC Summary for SO_2 Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Limit	Control
Ohio River Clean Fuels	Fire Pump Engines (300 Hp)	OH-0317	11/20/08	Sulfur Content ≤15 ppm	Ultra Low Sulfur Fuel
Competitive Power Ventures	Emergency Firewater Pump (300 Hp)	MD-0040	11/12/08	Sulfur Content ≤15 ppm	Ultra Low Sulfur Fuel
Tate & Lyle Ingredients Americas	Fire Pump Engine (575 Hp)	IA-0095	09/19/08	0.23 g/kW-hr	Low Sulfur Fuel

The most effective, technically feasible option identified is the use of ultra low sulfur distillate oil (≤0.0015% sulfur by weight).

2.11.3.3 *Establish BACT*

ABBK proposes to limit the fuel use in its emergency diesel fuel-fired CI engines to ultra low sulfur distillate oil (≤0.0015% sulfur by weight).

Due to the low rate of emissions from these emergency engines and the availability of diesel fuel that meets EPA mandated fuel sulfur standards, ABBK requests that BACT be established as the use of ultra low sulfur distillate oil (≤0.0015% sulfur by weight) rather than emission limits.

2.11.3.4 *BACT Compliance*

ABBK proposes to meet the firewater pump engine SO_2 BACT limit of ≤0.0015% sulfur by weight based on the use of ultra low sulfur distillate oil. ABBK will obtain a certificate of sulfur content from the fuel supplier and provide a copy to KDHE upon request to demonstrate compliance with BACT.

2.11.4 CO BACT Review

2.11.4.1 *Identify Available Control Options*

CO emissions may be emitted from the diesel fuel-fired CI engines. CO is formed as an intermediate combustion product that results when the reaction of CO to CO_2 is not completed. Incomplete CO oxidation occurs if there is a lack of oxygen near the fuel molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and can be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.

CO emission controls for limited use diesel fuel-fired CI engines that have been identified and considered in determining BACT include the following:

- Advanced engine design (per NSPS Subpart IIII) with combustion optimization;
- Catalytic oxidation; and
- Non-selective catalytic reduction (NSCR).

2.11.4.2 Eliminate Technically Infeasible Control Options

The use of NSCR is not considered technically feasible because this type of control device has not been demonstrated to function efficiently on lean-burn ICEs. The use of catalytic oxidation is not considered technically feasible due to temperature considerations. Catalytic converters do not function well at off-temperatures, and limited use engines such as the firewater pump engine and power back-up generator, run only infrequently at the proper temperature for such systems to work.

The emergency diesel fuel-fired CI engines that will be installed at the facility will meet specific design emission standards that are mandated by the NSPS Subpart IIII regulations, and these specific engine standards are dependent on when the engines are purchased. The NSPS Subpart IIII standard is a mandatory function that ensures certain engine standards are met, and the "feasible" engine design standards will increase with time. It is this NSPS standard that serves as the basis for this BACT determination.

2.11.4.3 Rank Technically Feasible Control Option

Based on the above discussion, the only technically feasible CO control technology identified for further evaluation as part of this BACT analysis is advanced engine design with good combustion control (combustion optimization).

2.11.4.4 Evaluate Technically Feasible Control Options

EPA's RBLC database was reviewed to identify CO control technologies that were potentially applicable to limited use diesel fuel-fired engines. The results of the database are summarized in Table 2-29.

Table 2–26
Emergency Diesel Fuel-fired CI Engines RBLC Summary for CO Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Limit	Control
Ohio River Clean Fuels	Fire Pump Engines (300 Hp)	OH-0317	11/20/08	2.6 g/Hp-hr	NSPS Tier II Certified
Competitive Power Ventures	Emergency Firewater Pump (300 Hp)	MD-0040	11/12/08	2.6 g/Hp-hr	NSPS Tier II Certified
Tate & Lyle Ingredients Americas	Fire Pump Engine (575 Hp)	IA-0095	09/19/08	2.6 g/Hp-hr	NSPS Tier II Certified

The most effective, technically feasible option identified is the use of the NSPS standard.

2.11.4.5 Establish BACT

Stationary firewater pump engines with a displacement of less than thirty liters per cylinder must comply with the emission standards in Table 4 of NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines(§§60.4200 through §§60.4219). For emergency engines with maximum engine power greater than 50 horsepower (hp) the manufacturer must certify, pursuant to 40 CFR 60.4202(a)(2), that the engine meets the standards for new non-road compression ignition engines for the same model year and maximum power listed in 40 CFR 89.112. It is assumed that the model to be chosen for this facility will be a 2011 or newer model and will meet the Tier 3 standards.

Due to the low rate of emissions from these emergency engines and the availability of engines that are certified to achieve these emission levels, ABBK requests that BACT be established as advanced engine design with good combustion control (combustion optimization), rather than emission limits.

2.11.4.6 BACT Compliance

ABHK proposes to install diesel fuel-fired engines that meet the applicable NSPS diesel emission standards as detailed in NSPS Subpart IIII for the applicable model year (i.e., for the year the engine is purchased). ABBK will provide a copy of the manufacturer's certification to KDHE upon request to demonstrate compliance with BACT.

2.11.5 PM/PM_{10} BACT Review

2.11.5.1 Identify Available Control Options

PM and PM_{10} emissions may be emitted from the diesel fuel-fired CI engines. Liquid particulates may appear as white smoke in the exhaust during an engine cold start, idling, or low load operations. These liquid particulates are formed in the quench layer adjacent to the cylinder walls, where the temperature is not high enough to ignite the fuel. Blue smoke is emitted when lubricating oil leak into the combustion chamber, often past worn piston rings, and are partially burned during the ignition of the fuel. Proper maintenance is the most effective method of preventing blue smoke emissions from all types of ICEs. Carbon particulates (soot) may be visible as black smoke, commonly associated with oxygen deficient regions in the combustion chamber.

PM/PM_{10} emission controls for limited use diesel fuel-fired CI engines that have been identified and considered in determining BACT include the following:

- Advanced engine design (per NSPS Subpart IIII) with combustion optimization;
- Diesel oxidizations catalysts (DOC); and
- Diesel particulate filters (DPF) or catalyzed diesel particulate filters (CDPF).

2.11.5.2 Eliminate Technically Infeasible Control Options

The use of DOCs, DPFs and CDPFs are not considered technically feasible because these types of control devices cannot be applied to limited-use

engines like the proposed emergency diesel fuel-fired CI engine. The emergency diesel fuel-fired engine that will be installed at the facility will meet specific design emission standards that are mandated by the NSPS Subpart IIII regulations, and these specific engine standards are dependent on when the engine is purchased. The NSPS Subpart IIII standard is a mandatory function that ensures certain engine standards are met, and the "feasible" engine design standards will increase with time. It is this NSPS standard that serves as the basis for this BACT determination.

2.11.5.3 *Rank Technically Feasible Options*

Based on the above discussion, the only technically feasible PM/PM_{10} control technology identified for further evaluation as part of this BACT analysis is advanced engine design with good combustion control (combustion optimization).

2.11.5.4 *Evaluate Technically Feasible Control Options*

EPA's RBLC database was reviewed to identify PM/PM_{10} control technologies that were potentially applicable to limited use diesel fuel-fired engines. The results of the database are summarized in Table 2-59.

Table 2–27
Emergency Diesel Fuel-fired CI Engines RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Limit	Control
Ohio River Clean Fuels	Fire Pump Engines (300 Hp)	OH-0317	11/20/08	0.40 g/Hp-hr	NSPS Tier II Certified
Competitive Power Ventures	Emergency Firewater Pump (300 Hp)	MD-0040	11/12/08	0.15 g/Hp-hr	NSPS Tier II Certified
Tate & Lyle Ingredients Americas	Fire Pump Engine (575 Hp)	IA-0095	09/19/08	0.15 g/Hp-hr	NSPS Tier II Certified

The most effective, technically feasible option identified is the use of the NSPS standard.

2.11.5.5 *Establish BACT*

Stationary firewater pump engines with a displacement of less than thirty liters per cylinder must comply with the emission standards in Table 4 of

NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines(§§60.4200 through §§60.4219). For emergency engines with maximum engine power greater than 50 horsepower (hp) the manufacturer must certify, pursuant to 40 CFR 60.4202(a)(2), that the engine meets the standards for new non-road compression ignition engines for the same model year and maximum power listed in 40 CFR 89.112. It is assumed that the model to be chosen for this facility will be a 2011 or newer model and will meet the Tier 3 standards.

Due to the low rate of emissions from these emergency engines and the availability of engines that are certified to achieve these emission levels, ABBK requests that BACT be established as advanced engine design with good combustion control (combustion optimization), rather than emission limits.

2.11.5.6 *BACT Compliance*

ABHK proposes to install diesel fuel-fired engines that meet the applicable NSPS diesel emission standards as detailed in NSPS Subpart IIII for the applicable model year (i.e., for the year the engine is purchased). ABBK will provide a copy of the manufacturer's certification to KDHE upon request to demonstrate compliance with BACT.

2.12 In-Plant Haul Roads BACT Analysis

2.12.1 Source Emissions

ABBK will construct paved in-plant haul roads for delivery of biomass, and other raw materials such as denaturant and process chemicals; as well as for shipment of products and by-products. Particulate emissions occur whenever vehicles travel over a paved surface, such as public and industrial roads and parking lots. These emissions may originate from material previously deposited on the travel surface, or re-suspension of material from tires and undercarriages. In general, emissions arise primarily from the surface material loading (measured as mass of material per unit area). Surface loading is in turn replenished by other sources (e.g., pavement wear, deposition of material from vehicles, deposition from other nearby sources, carryout from surrounding unpaved areas, and litter). Because of the importance

of the surface loading, available control techniques either attempt to prevent material from being deposited on the surface or to remove (from the travel lanes) any material that has been deposited.

Paved haul road potential emissions were calculated using AP-42, Chapter 13.2.1, *Paved Roads* (1/11) emission factors. ABBK plans to pave all in-plant haul roads; therefore, only mitigation control measures applicable to paved roads are addressed in this BACT analysis.

2.12.2 PM/PM_{10}/$PM_{2.5}$ BACT Review

2.12.2.1 *Identify Available Control Options*

The following control options are best management practices (BMPs) that have been identified and considered in determining BACT for the in-plant haul roads:

- Posting and limiting vehicle speeds;
- Use of wind fences or other wind breaks;
- Water spray/road washing;
- Chemical stabilization;
- Sweeping; and
- Combination of the controls identified above.

2.12.2.2 *Eliminate Technically Infeasible Control Options*

The above listed BMPs are all technically feasible and can be implemented at the site to mitigate particulate emissions.

2.12.2.3 *Rank Technically Feasible Control Options*

The combination of paved roads with wet suppression followed by vacuuming and/or sweeping represents the most effective control option for fugitive emissions. Control efficiencies of up to 95% can be achieved with frequent application. The second most effective control option is the combination of paved roads and either wet suppression or sweeping.

Control efficiencies for water flushing and sweeping are highly variable and dependent on application rates and frequency. In general, reported

control efficiencies for both approaches fall into a range of 25% to 58% compared to a baseline of paved roads without mitigative controls. The control efficiency of water flushing with a high application rate and frequency may be higher than with sweeping alone. However, in comparison to sweeping, water flushing has several potential drawbacks, including high water usage, potential water pollution and the frequent need for the water truck to return to a water source, generating increased vehicle tailpipe emissions.

2.12.2.4 Evaluate Technically Feasible Control Options

EPA's RBLC database was reviewed to identify $PM/PM_{10}/PM_{2.5}$ control technologies that were potentially applicable to paved in-plant haul roads. The results of the database search are summarized in Table 2-28.

Table 2–28
Paved Roads RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Limit	Control
Shintech Louisiana Plaquemine PVC Plant	Road – Fugitive Dust	LA-0201	02/27/09	PM_{10}: 0.22 lb/hr	Paving Roads as much as practical
Ohio River Clean Fuels	Roadways and Parking Areas (736,205 VMT/yr)	OH-0317	11/20/08	PM: 79.0 ton/yr PM_{10}: 15.39 ton/yr 0% Opacity	Reduced speed, sweeping, watering and good housekeeping measures
Southwest Electric Power Company	Unpaved Roads	AR-0094	11/05/08	PM: 1.1 lb/hr	Road maintenance plan with watering or dust suppression chemicals
Louisiana Generating Big Cajun 1 Power Plant	Paved Roads (33,000 VMT/yr)	LA-0223	01/08/08	PM_{10}: 1.21 lb/hr PM_{10}: 3.54 ton/yr PM_{10}: 0.2 lb/VMT	--
Aventine Renewable Energy Aurora West	Paved Haul Roads	NE-0046	09/27/07	Silt Load: 3 g/m^2	Develop, maintain and implement a fugitive control strategy and monitoring plan
Koda Energy	Road Traffic	NE-0074	08/23/07	NA	Sweeping
Homeland Energy Solutions	Internal Plant Roads	IA-0089	08/08/07	PM: 96.48 ton/yr PM_{10}: 18.78 ton/yr 0% Opacity	Best management practices with sweepers and dust suppression

Table 2–28
Paved Roads RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Limit	Control
Archer Daniels Midland Corn Processing Cedar Rapids	Haul Roads	IA-0088	06/29/07	None – No visible emissions permitted beyond property line	Daily sweeping and/or washing
Southwest Iowa Renewable Energy	Haul Roads	IA-0092	04/19/07	PM: 21.7 ton/yr	Vacuum sweeping and water flush daily

According to EPA's RBLC database, paved in-plant haul roads with fugitive dust controls such as daily sweeping and/or washing is ranked as the top control and has been established as BACT.

2.12.2.5 Establish BACT

ABBK proposes that BACT for the in-plant haul roads consist of the following:

- Paving of all in-plant haul roads;
- Post and enforce a maximum speed limit of 15 mph;
- Develop, maintain and implement a fugitive control strategy and monitoring plan; and
- No visible emissions beyond property boundary.

The proposed facility has committed to paving in-plant haul roads, performing frequent washing, vacuuming and sweeping, and enforcing a speed limit to reduce fugitive emissions from the paved plant haul roads.

Because the emission factor used to calculate the haul roads PTE is based on a fleet average, the use of hourly operational or truck count limits are not appropriate. The actual daily number of trucks carrying ethanol, biomass, and other materials or chemicals will fluctuate; however, the daily VMT estimates presented in detail in this application are based on the maximum daily facility-wide worst-case traffic. ABBK proposes that permit limits related to haul road emissions be based on the total number of trucks entering the facility daily regardless of material being hauled. The actual daily number of trucks carrying ethanol, biomass, and other

materials or chemicals will fluctuate as ABBK cannot guarantee 100% control of the delivery schedules from vendors or subcontractors.

2.12.2.6 BACT Compliance

ABBK proposes that the paved in-plant haul road BACT limit be based on a truck traffic limit calculated using a 7-day rolling average and visibility monitored to ensure there are no visible emissions beyond the property boundary. Further, a Fugitive Dust Control Plan will be developed and will detail the work practices to be implemented to reduce fugitive emissions from the unpaved biomass laydown roads and unpaved staging area. ABBK will also provide a copy of the Fugitive Dust Control Plan and associated documentation to KDHE upon request to demonstrate compliance with BACT.

2.13 Biomass Laydown Roads and Staging Area BACT Analysis

2.13.1 Source Emissions

ABBK will construct unpaved biomass laydown roads and an unpaved staging area for staging and storage of baled agricultural residues and energy crops. Similar to paved roads, particulate emissions occur whenever vehicles travel over a surface. The unpaved surfaces with have crushed and screened rock applied to strengthen the road surface and minimize fugitive dust.

Biomass laydown road potential emissions were amended in accordance with the Utah DEQ memorandum, *Emission Factors for Paved and Unpaved Haul Roads*, March 10, 2008. Emissions were calculated using AP-42, Chapter 13.2.2, *Unpaved Roads* (11/06) emission factors and an applied 70% control efficiency for chemical suppressant application and/or watering BMPs.

2.13.2 $PM/PM_{10}/PM_{2.5}$ BACT Review

2.13.2.1 Identify Available Control Options

The following control options have been identified and considered in determining BACT for the unpaved biomass laydown roads and an unpaved staging area:

- Paving;
- Posting and limiting vehicle speeds;
- Use of wind fences or other wind breaks;
- Water spray;
- Chemical stabilization; and
- Combination of the controls identified above.

2.13.2.2 *Eliminate Technically Infeasible Control Options*

Agricultural residues and energy crops are delivered in bale form exclusively on flatbed / module trucks to the facility. The baled biomass will either be unloaded directly onto conveyors supplying the grinding lines or unloaded at the biomass staging area or biomass storage field via the unpaved biomass laydown roads. The biomass staging area is utilized during the night shift and is located immediately adjacent to the biomass grinding lines to reduce traffic traveling in the biomass storage field. The biomass staging area and biomass storage field are constantly active as bales are brought onsite and stored as well as retrieved for use in the process during the night shift or during delivery disruptions.

Paving of the biomass laydown roads and staging area is not technically feasible due to the delivery method of the biomass bales. The module truck beds are designed such that the bed tips and extends off of the truck bed and rests directly on the ground. Due to the loading/unloading of bales from the trucks directly to the ground, there is significant pressure applied at the edge of the truck bed and the ground surface. Paved surfaces will be substantially degraded by the pressure of the trucks beds, such that the paved surfaces are not expected to withstand the activities.

2.13.2.3 *Rank Technically Feasible Control Options*

The combination of water or chemical suppression represents the most effective control option for fugitive emissions. Control efficiencies of up to 70% can be achieved with frequent application. The second most effective control option is the combination of paved roads and either wet suppression or sweeping.

2.13.2.4 Evaluate Technically Feasible Control Options

EPA's RBLC database was reviewed to identify PM/PM_{10} control technologies that were potentially applicable to unpaved roads. The results of the database search are summarized in Table 2-29.

Table 2–29
Biomass Laydown Roads and Staging Area RBLC Summary for PM/PM_{10} Emissions

Facility	Source Type	RBLC ID	Permit Date	BACT Limit	Control
Aggregate Industries Sloan Quarry	Hauling on Unpaved Road #1 (322.66 VMT/day)	NV-0045	12/11/06	PM_{10}: 7.57 lb/VMT PM_{10}: 2.25 ton/yr	Chemical dust suppressant
Aggregate Industries Sloan Quarry	Hauling on Unpaved Road #2 (533.33 VMT/day)	NV-0045	12/11/06	PM_{10}: 7.57 lb/VMT PM_{10}: 2.49 ton/yr	Chemical dust suppressant
Big River Industries Gravelite Division	Unpaved Roads	LA-0209	06/28/06	PM_{10}: 0.7 lb/hr PM_{10}: 3.05 ton/yr	Watering and reduced speed limit
Celco Power Rodemacher Brownfield Unit 3	Unpaved Roads	LA-0202	02/23/06	PM_{10}: 3.82 lb/hr PM_{10}: 3.82 ton/yr	Watering
Martco Oakdale OSB Plant	Unpaved Roads	LA-0203	06/13/05	PM_{10}: 0.29 lb/hr	Restricted access and chemical dust suppressant
Nucor Steel	Unpaved Roads	NC-0112	11/23/04	None	Water and chemical dust suppressant and 10 mph speed limit
Recmix of PA	Unpaved Roads	KY-0095	08/06/04	PM_{10}: 0.78 ton/yr	Watering

The most effective, technically feasible option identified for control of the fugitive emissions from unpaved haul roads is the use of water and chemical dust suppression with an enforced speed limit.

2.13.2.5 Establish BACT

ABBK proposes that BACT for the unpaved biomass laydown roads and an unpaved staging area consist of the following:

- Post and enforce a maximum speed limit of 15 mph;
- Develop, maintain and implement a fugitive control strategy and monitoring plan; and
- No visible emissions beyond property boundary.

The proposed facility has committed to performing frequent water and/or chemical dust suppressant application to reduce fugitive dust emissions from the unpaved biomass laydown roads and unpaved staging area. The biomass staging area immediately adjacent to the biomass grinding lines will be regularly utilized to reduce traffic traveling in the biomass storage field.

2.13.2.6 BACT Compliance

ABBK proposed that the unpaved biomass laydown roads and unpaved staging area BACT limit be based on a truck traffic limit calculated using a 7-day rolling average and visibility be monitored to ensure there are no visible emissions beyond the property boundary. Further, a Fugitive Dust Control Plan will be developed and will detail the work practices to be implemented to reduce fugitive emissions from the unpaved biomass laydown roads and unpaved staging area. ABBK will also provide a copy of the Fugitive Dust Control Plan and associated documentation to KDHE upon request to demonstrate compliance with BACT.

Section 3.0
Maximum Achievable Control Technology Analysis

3.1 Maximum Achievable Control Technology Requirements

The proposed facility will be a sythetic minor source for HAPs under K.A.R. 28-19-750, *Hazardous Air Pollutants; Maximum Achievable Control Technology*. Emissions will be controlled to below the major source thresholds defined in Title 40, Code of Federal Regulations, Part 63, Section 63.2 (40 CFR §63.2), *"Major source means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants"*. The control of emissions will be through the implementation of either Maximum Achievable Control Technology (MACT) or Generally Available Control Technology (GACT) that will be federally enforceable on all HAP emitting sources. The following is the MACT/GACT analysis for the proposed facility. This section details the control technologies proposed and the methods that will be used to demonstrate compliance.

The facility is requesting to limit its individual HAP emissions to not more than 9.9 tons per year and total HAP emissions to not more than 24.9 tons per year based on a 12-month rolling average. This HAP limit will establish the facility as a synthetic minor for the purposes of 40 CFR Part 63.

A summary of the MACT/GACT requirements for the units subject to specific NESHAPs are presented in Table 3-1. This section is organized by the applicable NESHAP. When appropriate, emission units with similar characteristics and MACT applicability are grouped together.

Table 3–1
Summary of Emission Units and Pollutants Subject to MACT/GACT and Limits

Stack ID	Equipment/Process	MACT/GACT Control Device(s) or Other Limitation(s)
EP-18185	EH Fermentation CO_2 Scrubber	Wet Scrubber
EP-02102	EH Ethanol Product Storage Tank	Internal Floating Roof
EP-02112	EH Ethanol Product Storage Tank	Internal Floating Roof
EP-02105	EH Denaturant Storage Tank	Internal Floating Roof
EP-02107	EH Product Shift Tank #1	Recordkeeping
EP-02108	EH Product Shift Tank #2	Recordkeeping
EP-2150	Ethanol Vapor Recovery System	Recordkeeping
EP-2150FUG	Ethanol Loading Losses	Recordkeeping
EP-02000	Fugitive Leaks	LDAR Program
EP-04001	EH Cooling Water Tower	Recordkeeping
EP-21001	CoGen Cooling Water Tower	Recordkeeping
EP-20001	Biomass-Fired Stoker Boiler	Spray Dryer Absorber, Fabric Filter & Good Combustion Practices

3.2 Applicable NESHAPs

Kansas has adopted the requirements of 40 CFR Part 63, *National Emissions Standards for Hazardous Air Pollutants for Source Categories*, by reference in K.A.R. 28-19-750, with the exception of 40 CFR §§63.12, 63.13, 63.13, 63.40 through 63.44 and subpart E.

Table 3–2
Summary of NESHAPs Applicable to Abengoa Bioenergy Biomass of Kansas

NESHAP (40 CFR Part 63)	Description	Affected Source
Subpart A	General Provisions	Applies to each affected facility with an applicable MACT standard.
Subpart FFFF	National Emission Standards for Hazardous Air Pollutants Miscellaneous Organic Chemical Manufacturing	Applies to the ethanol production – miscellaneous organic chemical production (MCPU).
Subpart JJJJJJ	National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers	Applies to the biomass-fired boiler

The following subsections identify and discuss in detail those potentially applicable NESHAPs for regulated sources and the applicability of MACT/GACT requirements.

3.2.1 Subpart A – General Provisions

Subpart A contains the general provisions of the NESHAPs for affected stationary sources. As such, NESHAP affected sources within the ABBK facility will be subject to the general provisions, to the extent that they apply. More specifically, the provisions of Subpart A apply to the owner or operator of any stationary source that emits or has the potential to emit any HAP listed in or pursuant to Section 112(b) of the CAA; and is subject to any standard, limitation, prohibition, or other federally enforceable requirement established pursuant to 40 CFR Part 63. General requirements may include notifications, monitoring, recordkeeping and/or performance testing of specific sources. Specific NESHAPs, as they apply to a specific source, are further described in the following subsections. ABBK will comply with the relevant provisions of 40 CFR Part 63, Subpart A as they become applicable during the permitting, construction, startup, and operation of the facility.

3.2.2 Subpart FFFF – National Emission Standard for HAPs for Miscellaneous Organic Chemical Manufacturing

Subpart FFFF is known as the Miscellaneous Organic NESHAP (MON). Subpart FFFF addresses control of HAP emissions from specific equipment in organic chemical manufacturing operations. Generally, this subpart would not be applicable to ABBK due to the proposed HAP limits; however, to ensure compliance with the proposed facility-wide HAP limits, recordkeeping and monitoring requirements of this rule will be applied to those source regulated under this rule at major source facilities to help ensure compliance with the proposed HAP limit.

According to 40 CFR §63.2435, ethanol production is one of the source categories to which the rule applies (SIC Industry Group 2869 / NAICS Code 325193). The final rule was published in the Federal Register on November 10, 2003 and EPA finalized certain revisions to this rule on July 14, 2006. Specifically, the MON applies to certain equipment that is part of a Miscellaneous Organic Chemical Manufacturing Process Unit (MCPU).

According to the rule, an MCPU is the facility-wide collection of equipment necessary to operate a miscellaneous organic chemical manufacturing process, as defined in §63.2550, that produces an organic chemical using the SIC code 2869 that is an organic HAP is listed in Section 112(b) of the CAA, and is not regulated under another subpart. An MCPU also includes any assigned storage tanks and product transfer racks; equipment in open systems that is used to convey or store water having the same concentration and flow characteristics as wastewater; and components such as pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, and instrumentation systems that are used to manufacture an organic chemical regulated under this subpart.

Based on the above discussion, Table 3-4 lists the equipment at the ABBK facility that would be subject to the MON if the facility was a major source for HAP emissions.

Table 3–3
MON Applicability Analysis Summary

Equipment Group	MON Category	Basis	Summary of Specific MON Control Requirements
Biomass Co-Fermentation and Distillation Equipment: • Saccharification and Co-Fermentation (Area 16000) • Ethanol Recovery (i.e., Distillation) (Area 18000) Emission Point: • Enzymatic Hydrolysis CO_2 Scrubber (EP-18185)	Each tank and process vent is designated a Group 1 Continuous Process Vent in accordance with §63.2455(b).	Data to allow total resource effectiveness (TRE) calculations do not exist at the time of this MON applicability analysis. ABBK is designating this equipment as Group 1 Continuous Process Vents.	Reduce emissions of total organic HAP by ≥98% or to an outlet process concentration ≤20 ppmvd as organic HAP or TOC by venting emissions through a closed-vent system to any combination of control devices (except a flare). These vents will be routed to wet scrubbers to meet this requirement.
Denatured Ethanol Storage Tank Equipment: • Denatured Ethanol Storage Tanks Emission Points: • EH Ethanol Product Storage Tank (EP-02102) • EH Ethanol Product Storage Tank (EP-02112)	Group 1 Storage Tank	Tank capacity is >10,000 gallons and the maximum true vapor pressure of total HAP at storage temperature is ≥0.69 kPa and ≤76.6 kPa.	Comply with the requirements of 40 CFR Part 63, Subpart WW. The installation of internal floating roofs per 40 CFR Part 60, Subpart Kb will meet the requirements of Subpart WW, and subsequently Subpart FFFF.
Denaturant Storage Tank Equipment: • Denaturant Storage Tank Emission Points: • EH Denaturant Storage Tank (EP-02105)	Group 1 Storage Tanks	Tank capacities are >10,000 gallons and the maximum true vapor pressure of total HAP at storage temperature is ≥0.69 kPa and ≤76.6 kPa.	Comply with the requirements of 40 CFR Part 63, Subpart WW. The installation of internal floating roofs per 40 CFR Part 60, Subpart Kb will meet the requirements of Subpart WW, and subsequently Subpart FFFF.

Table 3–3
MON Applicability Analysis Summary

Equipment Group	MON Category	Basis	Summary of Specific MON Control Requirements
Ethanol Production Process Tanks Equipment: • Process (Shift) Tanks Emission Points: • EH Product Shift Tank #1 (EP-02107) • EH Product Shift Tank #2 (EP-02108)	Group 2 Batch Process Vents	Vents collective uncontrolled batch vent HAP emissions are <3,000 lb/yr. Therefore these streams are not Group 1 Batch Process Vents per 40 CFR §63.2550.	None.
Denatured Ethanol Load-Out Equipment: • Truck and Rail Car Loading Rack • Meters • Filters • Pumps Emission Points: • Ethanol Vapor Recovery System (EP-2150) • Ethanol Loading Losses (EP-2150FUG)	Group 2 Transfer Rack	The rack-weighted average partial pressure of HAP for load-out of denatured ethanol is <1.5 psia. Therefore the load-out rack is not a Group 1 Transfer Rack per 40 CFR §63.2550.	None.
Equipment Leaks • Biomass Fermentation and Distillation • Denatured Ethanol Transfer and Handling • Anhydrous Ethanol Transfer and Handling • Denatured Ethanol Load-Out	Not in organic HAP service	Equipment contains <5% by weight organic HAP. Therefore this equipment is not in organic HAP service per 40 CFR §63.2550.	None.
Equipment Leaks • Denaturant Transfer and Handling	In organic HAP service	Equipment contains ≥5% by weight organic HAP.	LDAR program pursuant to 40 CFR Part 60, Subpart VVa, or 40 CFR Part 65, Subpart F.

Table 3–3
MON Applicability Analysis Summary

Equipment Group	MON Category	Basis	Summary of Specific MON Control Requirements
Cooling Water Systems	Heat Exchange System	A heat exchange system means any cooling tower system or once-through cooling water system as defined at 40 CFR §63.101(b). The cooling water towers and chilled water system will contain <5% by weight of total HAPs listed in table 4 of Subpart F.	None.
Wastewater System	Group 2 Wastewater Stream	Total annual organic HAP concentration is <10,000 ppm by weight at all flow rates, <1000 ppm by weight annual average concentration and <200 lb/yr in the total annual load.	None.

Biomass Co-Fermentation and Distillation

The co-fermentation and distillation equipment vents would likely be subject to the new Group 1 continuous process vent emission limits and work practice standards of Table 1 of Subpart FFFF if the facility was a major source of HAP emissions for the following reasons:

1. The affected sources will start-up after November 10, 2003;
2. The co-fermentation and distillation equipment vents are expected to have a total resource effectiveness (TRE) index value of less than 5.0;
3. The co-fermentation and distillation equipment vents meet the definition of continuous process vents; and
4. The co-fermentation and distillation equipment vent streams will have mass emission rates of halogen atoms (chlorine and/or fluorine) contained in organic compounds of less than 0.45 kilograms per hour.

ABBK is designating the co-fermentation and distillation equipment vents as Group 1 vents for purposes of evaluating the MON control requirements.

The Group 1 continuous process vents would be required to either reduce emissions of total organic HAP by greater than or equal to 98% or to an outlet process concentration less than or equal to 20 ppmvd as organic HAP or TOC from the vent stream if the facility was a major source of HAP emissions. This emission rate reduction was used by ABBK as a design parameter for the packed tower wet scrubbers.

Denatured Ethanol Storage Tanks

The new denatured ethanol storage tanks (T-02102 and T-02112) would be classified as Group 1 storage tanks if the facility was a major source of HAP emissions. The tanks would be classified as a Group 1 tank because they have a capacity of greater than 10,000 gallons (i.e., 460,000 gallons) and a maximum true vapor pressure of greater than 0.69 kPa but less than 76.6 kPa (calculated as 5.2 kPa from an average vapor pressure of 0.7494 psia, as obtained from the TANKS 4.0.9d emissions report). Per Subpart FFFF, compliance with the requirements of the provisions of 40 CFR Part 60, Subpart Kb constitutes compliance with the

requirements of Subpart FFFF. ABBK will design the tanks such that they will meet with the applicable requirements of 40 CFR Part 60, Subpart Kb, thereby meet the Subpart FFFF requirements.

Denaturant Storage Tank

The denaturant storage tank (T-02105) would be classified as a Group 1 storage tank if the facility was a major source of HAP emissions. The tank is classified as a Group 1 tank because it has a capacity of greater than 10,000 gallons (i.e., 22,500 gallons) and has a maximum true vapor pressure of greater than 0.69 kPa but less than 76.6 kPa (calculated as 45.5 kPa from an average vapor pressure of 6.5993 psia, as obtained from the TANKS 4.0.9d emissions report). Per Subpart FFFF, compliance with the requirements of the provisions of 40 CFR Part 60, Subpart Kb constitutes compliance with the requirements of Subpart FFFF. ABBK will design the tank such that it will meet with the applicable requirements of 40 CFR Part 60, Subpart Kb, thereby meet the Subpart FFFF requirements.

Ethanol Production Process Tanks

The new product shift tanks (T-02107 and T-02108) would be classified as Group 2 batch process vents if the facility was a major source of HAP emissions. The tanks are classified as a Group 2 batch process vents because these tank vents' collective uncontrolled batch vent HAP emissions are less than 3,000 lb/yr. These tanks are not subject to any requirements under Subpart FFFF.

Denatured Ethanol Load-Out

The new ethanol load-out operation will have a transfer rack average vapor pressure of less than 1.5 psia. Based on the average vapor pressure, the ethanol load-out transfer rack would be classified as a Group 2 transfer rack if the facility was a major source of HAP emissions. Subpart FFFF does not contain any requirements that apply to the ethanol load rack, other than the requirement that the source maintain records in accordance with 40 CFR §63.2525, indicating that the transfer rack average partial pressure is less than 1.5 psia. The transfer rack average partial pressure must be calculated in accordance with 40 CFR §63.111.

Equipment Leaks

The only equipment leaks that would be subject to the requirements of Subpart FFFF if the facility was a major source of HAP emissions are those pumps and valves that are associated with the transfer and handling of denaturant. ABBK will comply with the requirements of Subpart FFFF applicable to these equipment leaks by meeting the requirements of 40 CPR Part 60, Subpart VVa. The engineering estimate of total OLD regulated organic HAP concentration in the anhydrous ethanol is 520 ppmw. This is approximately 0.052% by weight, which is significantly less than the 5% by weight threshold required to be subject to this subpart. Denatured ethanol also contains the main organic HAPs from gasoline: benzene, cumene, ethylbenzene, toluene, and xylene. The engineering estimate of total OLD regulated organic HAP concentration in the denatured ethanol is 0.04% by weight from the gasoline (0.815% by weight in gasoline, blended with anhydrous ethanol at 4.8% by weight) plus the 0.052% by weight from the ethanol, which equals 0.09% by weight total OLD regulated HAP, which is significantly less than the 5% by weight threshold required to be subject to this subpart.

Cooling Water Systems

The cooling water systems would be classified as heat exchange systems if the facility was a major source of HAP emissions as they meet the definition of a "heat exchange system", as defined at 40 CFR §63.101(b). The recirculating heat exchange systems used to cool process fluids will contain <5% by weight of total HAPs listed in table 4 of Subpart F, thereby meeting Subpart FFFF requirements.

Wastewater System

The ethanol plant wastewater streams would be classified as Group 2 wastewater streams if the facility was a major source of HAP emissions. The total annual organic HAP concentration is <10,000 ppm by weight at all flow rates, <1000 ppm by weight annual average concentration and <200 lb/yr in the total annual load. ABBK will meet the recordkeeping requirements of Subpart FFFF (i.e., identification of wastewater stream, estimation of HAP concentration, and flow rate) for the ethanol wastewater streams.

3.2.3 *Subpart DDDDD – National Emission Standards for HAPs for Industrial, Commercial and Institutional Boilers and Process Heaters*

This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from new and existing industrial, commercial, and institutional boilers and process heaters that use non-hazardous solid, liquid and gaseous fuels. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards. This subpart does not apply to the proposed biomass-fired boilers (BL-20001) as the facility has proposed HAP emission limits below major source thresholds.

3.2.4 *Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers*

This subpart establishes national emission limits and work practice standards for area sources of hazardous air pollutants (HAP) emitted from new and existing industrial, commercial, and institutional boilers and process heaters that use non-hazardous solid, liquid and gaseous fuels. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards. This subpart applies to the proposed biomass-fired boiler (BL-20001) as the facility has proposed HAP emission limits below major source thresholds.

Because this standard does not list any control requirements for HAPs other than particulate matter, components of 40 CFR Part 63, Subpart DDDDD will be relied upon to establish recordkeeping and monitoring requirements to help ensure compliance with the proposed facility-wide HAP limit. Specifically, Tables 4 through 8 to Subpart DDDDD will be relied upon for PM, HCl and CO and the corresponding control equipment discussed in the BACT analysis.

Section 4.0
Code of Federal Regulations not specifically addressed in the Kansas Administrative Regulations

4.1 Code of Federal Regulations

The Federal CAA and CAA Amendments set forth regulatory requirements for air emission sources. These regulations are set forth under Title 40 of the Code of Federal Regulations and administered by the EPA or delegated authority. For the most part, Kansas has adopted regulations to implement the federal air quality regulations in its state implementation plan, and has received federal approval for those regulations. This section reviews potentially applicable requirements in the Code of Federal Regulations not specifically addressed in the K.A.R.

4.1.1 Compliance Assurance Monitoring (40 CFR Part 64)

The CAA requires compliance assurance monitoring (CAM) for major stationary sources of air pollution that are required to obtain operating permits under the Title V program. CAM requirements are outlined in 40 CFR Part 64. CAM requires monitoring for each emissions unit that is a large Pollutant Specific Emissions Unit (PSEU), and that relies on pollution control equipment to achieve compliance with one or more emission standards. CAM requirements do include sources of hazardous air pollutants and emission standards for hazardous air pollutants.

The biomass-fired boiler is subject to CAM. The boiler is considered a large (PSEU, i.e. they are an emission unit with potential controlled emissions equal to or greater than 100% of the major source threshold of the Title V program for any given regulated pollutant. The potential controlled emissions from the boiler for NOx, SO_2 and CO are over 100 ton/yr, and thus were reviewed for applicability to CAM. The remaining emissions units at the facility are not considered large PSEU, since controlled emissions are less than 100 ton/yr.

Table 4-1 presents to CAM applicability determination for the biomass-fired boiler.

Table 4–1
CAM Applicability Summary for the Biomass-Fired Boilers

Stack ID	Equipment/Process	Pollutant	Control Device(s) or Operational Limitation(s)	Subject to CAM?
EP-20001	Biomass-Fired Boiler	NOx	BACT – SNCR	Exempt from CAM due to 40 CFR Part 60 Subpart Db requirement to use CEMS
		SO_2	BACT – SDA	Exempt from CAM due to 40 CFR Part 60 Subpart Db requirement to use CEMS
		CO	BACT – GCP	Exempt from CAM due to GACT requirement to use CEMS

4.1.2 Chemical Accident Prevention Provisions (40 CFR Part 68)

Facilities that produce, store or use regulated toxic substances in excess of the thresholds noted in 40 CFR Part 68, are subject to the Chemical Accident Prevention Provisions. Specifically, Part 68 requires the preparation and compliance of a facility specific Risk Management Plan (RMP). These regulations are often referred to as 112(r). ABBK may be subject to RMP requirements for the storage of certain chemicals on-site. As such, the facility will submit to the EPA, an RMP as required prior to the startup of the storage tanks and related equipment.

4.1.3 Acid Rain Program (40 CFR Part 72)

The Federal acid rain program requirements of 40 CFR Part 72 is not applicable to ABBK, because the biomass-fired boiler will not generate electricity for commercial sale.

4.1.4 Protection of Stratospheric Ozone (40 CFR Part 82)

Guidelines for the protection of stratospheric ozone were established by the CAA and are outlined in 40 CFR Part 82. ABBK may be regulated under these standards if ozone depleting compounds or activities are stored or conducted on-site. One potential regulated activity at the facility is the use of a halogenated photochemically active compound (Halon) for fire protection systems. If ABBK determines that on-site fire protection equipment at the facility is subject to the protection of stratospheric ozone standards, it will implement the required compliance actions and submit any required reports.

Appendix A

1) EPA's RACT/BACT/LAER Clearinghouse (RBLC) Search Results for Process Type 11.000 – Utility and Large Industrial Size Boilers/Furnaces (>250 MMBtu/hr), Subcategory Type 11.120 – Biomass.
2) Detailed Costs Analysis of Selective Catalytic Reduction Control for the Biomass-Fired Stoker Boiler.
3) Detailed Costs Analysis of Selective Non-Catalytic Reduction Control for the Biomass-Fired Stoker Boiler.

Selective Non-Catalytic Reduction (SNCR) Control Technology Parameters for Stoker Boiler

Air Pollution Control Cost Manual, Sixth Edition, Section 4 – NOx Controls, Section 4.1 - Selective Non-Catalytic Reduction, U.S. Environmental Protection Agency, EPA 452/B 02 001, July 2002.
Control technology cost analysis based on the installation of an SCR only, with no upstream reagent injections/SNCR.
Costs adjusted from 1998 dollars to 2011 dollars based on a 38% inflation rate.

SCR Equation Inputs

Variable	Description	Value	Units	Notes
Q_b	Boiler Size	500	MMBtu/hr	
NOx_{in}	NOx inlet	0.76	lb/MMBtu	
NOx_{out}	NOx outlet	0.42	lb/MMBtu	
	Annual NOx removed	653.93	ton/yr	Based on t_{ops}
η_{NOx}	NOx removal efficiency	0.45		Targeted rate for SNCR
	Annual average fuel consumption	269,885	dry ton/yr	
	Annual maximum fuel consumption	296,463	dry ton/yr	
CF_{plant}	Plant capacity factor	0.91		Eqn 1.7
CF_{SNCR}	SNCR capacity factor	0.96		Eqn 1.8
CF_{total}	Total system capacity factor	0.87		Eqn 1.6
S	Sulfur content of fuel (weight fraction)	0.98	% by weight	
T	Gas temperature	600	degF	

SCR Parameter Estimates

Variable	Description	Value	Units	Reference
NSR	Normal Stoichiometric Ratios	1.1		Page 1-24
SR_T	Ratio of moles of ammonia per mole of reagent injected	1		Page 1-24
ASR	Actual Stoichiometric Ratios	1.10		Eqn 1.12
Utilization	Reagent utilization	0.41		Eqn 1.13
$M_{reagent}$	Molecular weight of ammonia	17.03	g/mole	Page 1-26
M_{NOx}	Molecular weight of NOx	46.01	g/mole	Page 1-26
$m_{reagent}$	Reagent mass of flow rate	69.64	lb/hr	Eqn 1.15
C_{sol}	Percent concentration of the aqueous reagent solution by weight	0.995		Page 1-27
m_{sol}	Mass flow rate of aqueous ammonia solution	69.99	lb/hr	Eqn 1.16
ρ_{sol}	Density of the aqueous reagent solution (99.5% at 60 degF)	38.15	lb/ft^3	Page 1-27
v_{sol}	Specific volume of the aqueous reagent solution (99.5% at 60 degF)	7.48	gal/ft^3	Page 1-27
q_{sol}	Solution volume flow rate	1.8	gal/hr	Eqn 1.17
t	Total number of days aqueous ammonia tank capacity	14		Estimated
	Ammonia Tank Volume, rounded	1,000	gal	Eqn 1.18
t_{ops}	Total operating time of plant	7,647	hr/yr	Eqn 1.22a
$Cost_{reagent}$	Ammonia unit fee	$ 1.70	$/gal	Estimated
Reagent	Annual reagent cost	$ 23,848	$/yr	Eqn 1.22
	Electrical power consumption	20.68	kW	Eqn 1.23
$Cost_{power}$	Electrical power unit fee	$0.065	$/kW	Estimated
Power	Electrical power costs	$10,281	$/yr	Eqn 1.24
n	Life of SNCR system	20	yr	Page 1-37
i	Interest rate	8.5%		Corp BB rating
CRF	Capital Recovery Factor	0.11		Eqn 1.34

Selective Non-Catalytic Reduction (SNCR) Control Technology Parameters for Stoker Boiler

CAPITAL COSTS (Excluding Site Preparation and Building Costs)			
1) DIRECT PURCHASE EQUIPMENT COSTS (PEC)	**$**	**1,981,600**	
a) Equipment cost, adjusted for inflation (38% assumed)	$	1,679,322	Eqn 1.19
b) Instrumentation	$	167,932	0.1 x EC
c) Sales tax	$	50,380	0.03 x EC
d) Freight	$	83,966	0.05 x EC
2) DIRECT INSTALLATION COSTS (DIC)	**$**	**653,928**	
a) Foundation and supports	$	198,160	0.1 x PEC
b) Handling and erection	$	396,320	0.2 x PEC
c) Electrical	$	19,816	0.01 x PEC
d) Ducting	$	19,816	0.01 x PEC
e) Insulation and painting	$	19,816	0.01 x PEC
3) DIRECT CONTINGENCY	**$**	**198,160**	**0.1 x PEC**
TOTAL DIRECT CAPITAL COSTS (DC)	**$**	**2,833,688**	
4) OTHER INDIRECT CAPITAL COSTS (INSTALLATION)	**$**	**733,192**	
a) Engineering	$	198,160	0.1 x PEC
b) Construction and field expenses	$	99,080	0.05 x PEC
c) Contractor fees	$	198,160	0.1 x PEC
d) Start-up	$	39,632	0.02 x PEC
e) Performance test	$	198,160	0.1 x PEC
5) INDIRECT CONTINGENCY	**$**	**146,638**	**0.2 x IC**
TOTAL INDIRECT CAPITAL COSTS (IC)	**$**	**879,831**	
TOTAL CAPITAL INVESTMENT (TCI)	**$**	**3,713,519**	**DC + IC**

ANNUAL COSTS			
1) DIRECT ANNUAL COSTS (DC)	**$**	**79,551**	**Eqn 1.20**
a) Annual Maintenance	$	55,703	Eqn 1.21
b) Annual Reagent Cost	$	23,848	Eqn 1.22
Aactual reagent will be anhydorus ammonia; therefore, there are no additional costs associated with volatization of injected water.			
2) INDIRECT ANNUAL COTS (IC)	**$**	**588,682**	
a) Overhead	$	47,730	60% Labor and Materials
b) Administrative Charges	$	74,270	2% of TCI
c) Property Taxes	$	37,135	1% of TCI
d) Insurance	$	37,135	1% of TCI
e) Capital Recovery	$	392,411	Eqn 1.33
TOTAL ANNUAL COST	**$**	**668,233**	**Eqn 1.35**

Cost Effectiveness, dollars per ton of NOx removed	**$**	**1,022**	**Eqn 1.37**

Selective Catalytic Reduction (SCR) Control Technology Parameters for Stoker Boiler

Air Pollution Control Cost Manual, Sixth Edition, Section 4 – NOx Controls, Section 4.2 - Selective Catalytic Reduction, U.S. Environmental Protection Agency, EPA 452/B 02 001, March 2003.
Control technology cost analysis based on the installation of an SCR only, with no upstream reagent injections/SNCR.
Costs adjusted from 1998 dollars to 2011 dollars based on a 38% inflation rate.

SCR Equation Inputs

Variable	Description	Value	Units	Notes
Q_b	Boiler Size	500	MMBtu/hr	
NOx_{in}	NOx inlet	0.76	lb/MMBtu	
NOx_{out}	NOx outlet	0.30	lb/MMBtu	
	Annual NOx removed	871.75	ton/yr	Based on t_{ops}
η_{NOx}	NOx removal efficiency	0.60		Targeted rate for SCR
	Annual average fuel consumption	269,885	dry ton/yr	
	Annual maximum fuel consumption	296,463	dry ton/yr	
CF_{plant}	Plant capacity factor	0.91		Eqn 2.7
CF_{SCR}	SNCR capacity factor	0.96		Eqn 2.8
CF_{total}	Total system capacity factor	0.87		Eqn 2.6
S	Sulfur content of fuel (weight fraction)	0.98	% by weight	
T	Gas temperature	600	degF	

SCR Parameter Estimates

Variable	Description	Value	Units	Reference
q_{fuel}	Volumetric flow rate for fuel	528	ft^3/min-MMBtu/hr	Calculated
$q_{fuel\ gas}$	Flue gas flow rate	252,621	acfm	ABBK
NSR	Normal Stoichiometric Ratios	1.1		Page 1-24
ASR	Actual Stoichiometric Ratios	1.05		Eqn 2.11
Slip	Theoretical ammonia slip	0.45	ppmv	Eqn 2.17
η_{adj}	NOx efficiency adjustment factor	0.92		Eqn 2.20
NOx_{adj}	NOx adjustment factor for inlet NOx	1.10		Eqn 2.21
$Slip_{adj}$	Ammonia slip adjustment factor for ammonia slips between 2 and 5 ppm	1.26		Eqn 2.22
S_{adj}	Sulfur adjustment factor	1.01		Eqn 2.23
T_{adj}	The temperature adjustment factor	1.40		Eqn 2.24
N_{SCR}	Number of reactor chambers	1		Estimated
$Vol_{catalyst}$	Volume of catalyst	2524	ft^3	Eqn 2.19
$A_{catalyst}$	Catalyst cross sectional area	263.15	ft^2	Eqn 2.25
A_{SCR}	Reactor cross sectional area	302.62	ft^2	Eqn 2.26
l	length and width of reactor	17.40	ft	Eqn 2.27
h'_{layer}	Nominal catalyst height	3.1	ft	Page 2-38
n_{layer}	Number of catalyst layers	4		Eqn 2.28
h_{layer}	Height of each layer	3.40	ft	Eqn 2.29
n_{empty}	Number of empty catalyst layers	1		Page 2-39
n_{total}	Number of total catalyst layers	5		Eqn 2.3
C_1	Constant for h_{SCR} equation	7		Page 2-39
C_2	Constant for h_{SCR} equation	9		Page 2-39
h_{SCR}	Height of SCR reactor	60.99	ft	Eqn 2.31
$M_{reagent}$	Molecular weight of ammonia	17.03	g/mole	Page 2-39
M_{NOx}	Molecular weight of NOx	46.01	g/mole	Page 2-39
SR_T	Ratio of moles of ammonia per mole of reagent injected	1		Page 1-24
$m_{reagent}$	Reagent mass of flow rate	92.83	lb/hr	Eqn 2.32
C_{sol}	Percent concentration of the aqueous reagent solution by weight	0.995		Page 2-39
m_{sol}	Mass flow rate of aqueous ammonia solution	93.30	lb/hr	Eqn 2.33
ρ_{sol}	Density of the anhydrous reagent solution (99.5% at 60 degF)	38.15	lb/ft^3	Page 2-39
v_{sol}	Specific volume of the aqueous reagent solution (29% at 60 degF)	7.48	gal/ft^3	Page 2-39
q_{sol}	Solution volume flow rate	18.3	gal/hr	Eqn 2.34
t	Total number of days aqueous ammonia tank capacity	14		Estimated
	Ammonia Tank Volume, rounded	7,000	gal	Eqn 2.35
t_{ops}	Total operating time of plant	7,647	hr/yr	Eqn 1.22a
ΔP_{duct}	Pressure drop (uses mid-range value)	2.5	inches H_2O	Page 2-46
$\Delta P_{catalyst}$	Pressure drop (uses mid-range value)	0.875	inches H_2O	Page 2-46

Selective Catalytic Reduction (SCR) Control Technology Parameters for Stoker Boiler

SCR Parameter Estimates				
Variable	Description	Value	Units	Reference
$q_{reagent}$	Ammonia volume flow rate (assumed same as solution flow rate, q_{sol})	18	gal/hr	Estimated
$Cost_{reagent}$	Ammonia unit fee	$ 1.70	$/gal	Estimated
Reagent	Annual reagent cost	$ 237,831	$/yr	Eqn 2.47
	Natural gas consumption	5	MMBtu/hr	Estimated
$Cost_{nat\ gas}$	Natural gas unit fee	$ 6.00	$/MMBtu	Estimated
Gas	Natural gas costs	$ 229,408	$/yr	Calculated
	Electrical power consumption	204.41	kW	Eqn 2.48
$Cost_{power}$	Electrical power unit fee	$0.065	$/kW	Estimated
Power	Electrical power costs	$101,602	$/yr	Eqn 2.49
$CC_{replace}$	Cost of catalyst, scaled to 2011dollars (38% inflation rate assumed)	$ 331.20	$/ft^3	Page 2-43
Catalyst	Catalyst replacement cost	$ 209,023.30	$/catalyst life	Eqn 2.5
Y	Life of catalyst, catalyst deactivation exacerbate due to high SO_2 conc.	3	yr	Estimated
n	Life of SCR system	20	yr	Page 2-48
i	Interest rate	8.5%		Corp BB Rating
FWF	Future worth factor	0.31		Eqn 2.52
CRF	Capital Recovery Factor	0.11		Eqn 2.55

CAPITAL COSTS (Excluding Site Preparation and Building Costs)			
1) DIRECT PURCHASE EQUIPMENT COSTS (PEC)	**$**	**5,598,156**	
a) Equipment cost, adjusted for inflation (38% assumed)	$	4,744,200	Eqn 2.36
$f(h_{SCR})$	$	255.81	Eqn 2.37
$f(NH_3)$	$	40.03	Eqn 2.38
f(new)	$	(1,004.64)	Eqn 2.40
$f(VOL_{catalyst})$	$	836,093	Eqn 2.43
b) Instrumentation	$	474,420	0.1 x EC
c) Sales tax	$	142,326	0.03 x EC
d) Freight	$	237,210	0.05 x EC
2) DIRECT INSTALLATION COSTS (DIC)	**$**	**1,959,355**	
a) Foundation and supports	$	559,816	0.1 x PEC
b) Handling and erection	$	1,119,631	0.2 x PEC
c) Electrical	$	55,982	0.01 x PEC
d) Ducting	$	55,982	0.01 x PEC
e) Insulation and painting	$	55,982	0.01 x PEC
f) Stack modifications	$	111,963	0.02 x PEC
3) DIRECT CONTINGENCY	**$**	**559,816**	**0.1 x PEC**
TOTAL DIRECT CAPITAL COSTS (DC)	**$**	**8,117,326**	
4) OTHER INDIRECT CAPITAL COSTS (INSTALLATION)	**$**	**2,071,317.70**	
a) Engineering	$	559,816	0.1 x PEC
b) Construction and field expenses	$	279,908	0.05 x PEC
c) Contractor fees	$	559,816	0.1 x PEC
d) Start-up	$	111,963	0.02 x PEC
e) Performance test	$	559,816	0.1 x PEC
5) INDIRECT CONTINGENCY	**$**	**414,264**	**0.2 x IC**
TOTAL INDIRECT CAPITAL COSTS (IC)	**$**	**2,485,581**	
TOTAL CAPITAL INVESTMENT (TCI)	**$**	**10,602,907**	**DC + IC**

ANNUAL COSTS			
1) DIRECT ANNUAL COSTS (DC)	**$**	**791,958**	**Eqn 2.45**
a) Annual Maintenance	$	159,044	Eqn 2.46
b) Annual Reagent Cost	$	237,831	Eqn 2.47
c) Annual Natural Gas Cost	$	229,408	Estimated
d) Annual Electricity Cost	$	101,602	Eqn 2.48
e) Annual Catalyst Cost	$	64,074	Eqn 2.50
2) INDIRECT ANNUAL COTS (IC)	**$**	**2,019,711**	
a) Overhead	$	475,175	60% Labor and Materials
b) Administrative Charges	$	212,058	2% of TCI
c) Property Taxes	$	106,029	1% of TCI
d) Insurance	$	106,029	1% of TCI
e) Capital Recovery	$	1,120,420	Eqn 2.54
TOTAL ANNUAL COST	**$**	**2,811,669**	**Eqn 2.56**

Cost Effectiveness, dollars per ton of NOx removed	**$**	**3,225**	**Eqn 2.58**

Incremental Annual Cost, dollars per year	**$**	**2,143,436**
Incremental NOx Reductions, tons per year		**217.82**
Incremental Cost per Ton NOx Reduced, dollars per ton	**$**	**9,840**

Selective Non_Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) Control Technology Parameters for Stoker Boiler

Air Pollution Control Cost Manual, Sixth Edition, Section 4 – NOx Controls, Section 4.2 - Selective Catalytic Reduction, U.S. Environmental Protection Agency, EPA 452/B 02 001, March 2003.
Control technology cost analysis based on the installation of an SCR with an SNCR upstream.
Costs adjusted from 1998 dollars to 2011 dollars based on a 38% inflation rate.

SCR Equation Inputs

Variable	Description	Value	Units	Notes
Q_b	Boiler Size	500	MMBtu/hr	
NOx_{in}	NOx inlet	0.42	lb/MMBtu	
NOx_{out}	NOx outlet	0.23	lb/MMBtu	
	Annual NOx removed	359.60	ton/yr	Based on t_{ops}
η_{NOx}	NOx removal efficiency	0.45		Targeted rate for SCR downstream of SNCR
	Annual average fuel consumption	269,885	dry ton/yr	
	Annual maximum fuel consumption	296,463	dry ton/yr	
CF_{plant}	Plant capacity factor	0.91		Eqn 2.7
CF_{SCR}	SNCR capacity factor	0.96		Eqn 2.8
CF_{total}	Total system capacity factor	0.87		Eqn 2.6
S	Sulfur content of fuel (weight fraction)	0.98	% by weight	
T	Gas temperature	600	degF	

SCR Parameter Estimates

Variable	Description	Value	Units	Reference
q_{fuel}	Volumetric flow rate for fuel	528	ft^3/min-MMBtu/hr	Calculated
$q_{fuel\ gas}$	Flue gas flow rate	252,621	acfm	ABBK
NSR	Normal Stoichiometric Ratios	1.1		Page 1-24
ASR	Actual Stoichiometric Ratios	1.05		Eqn 2.11
Slip	Theoretical ammonia slip	0.60	ppmv	Eqn 2.17
η_{adj}	NOx efficiency adjustment factor	0.76		Eqn 2.20
NOx_{adj}	NOx adjustment factor for inlet NOx	0.99		Eqn 2.21
$Slip_{adj}$	Ammonia slip adjustment factor for ammonia slips between 2 and 5 ppm	1.25		Eqn 2.22
S_{adj}	Sulfur adjustment factor	1.01		Eqn 2.23
T_{adj}	The temperature adjustment factor	1.40		Eqn 2.24
N_{SCR}	Number of reactor chambers	1		Estimated
$Vol_{catalyst}$	Volume of catalyst	1868	ft^3	Eqn 2.19
$A_{catalyst}$	Catalyst cross sectional area	263.15	ft^2	Eqn 2.25
A_{SCR}	Reactor cross sectional area	302.62	ft^2	Eqn 2.26
l	length and width of reactor	17.40	ft	Eqn 2.27
h'_{layer}	Nominal catalyst height	3.1	ft	Page 2-38
n_{layer}	Number of catalyst layers	3		Eqn 2.28
h_{layer}	Height of each layer	3.37	ft	Eqn 2.29
n_{empty}	Number of empty catalyst layers	1		Page 2-39
n_{total}	Number of total catalyst layers	4		Eqn 2.3
C_1	Constant for h_{SCR} equation	7		Page 2-39
C_2	Constant for h_{SCR} equation	9		Page 2-39
h_{SCR}	Height of SCR reactor	50.46	ft	Eqn 2.31
$M_{reagent}$	Molecular weight of ammonia	17.03	g/mole	Page 2-39
M_{NOx}	Molecular weight of NOx	46.01	g/mole	Page 2-39
SR_T	Ratio of moles of ammonia per mole of reagent injected	1		Page 1-24
$m_{reagent}$	Reagent mass of flow rate	38.29	lb/hr	Eqn 2.32
C_{sol}	Percent concentration of the aqueous reagent solution by weight	0.995		Page 2-39
m_{sol}	Mass flow rate of aqueous ammonia solution	38.48	lb/hr	Eqn 2.33
ρ_{sol}	Density of the anhydrous reagent solution (99.5% at 60 degF)	38.15	lb/ft^3	Page 2-39
v_{sol}	Specific volume of the aqueous reagent solution (99.5% at 60 degF)	7.48	gal/ft^3	Page 2-39
q_{sol}	Solution volume flow rate	7.5	gal/hr	Eqn 2.34
t	Total number of days aqueous ammonia tank capacity	14		Estimated
	Ammonia Tank Volume, rounded	3,000	gal	Eqn 2.35
t_{ops}	Total operating time of plant	7,647	hr/yr	Eqn 1.22a
ΔP_{duct}	Pressure drop (uses mid-range value)	2.5	inches H_2O	Page 2-46
$\Delta P_{catalyst}$	Pressure drop (uses mid-range value)	0.875	inches H_2O	Page 2-46

Selective Non_Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) Control Technology Parameters for Stoker Boiler

SCR Parameter Estimates				
Variable	Description	Value	Units	Reference
$q_{reagent}$	Ammonia volume flow rate (assumed same as solution flow rate, q_{sol})	8	gal/hr	Estimated
$Cost_{reagent}$	Ammonia unit fee	$ 1.70	$/gal	Estimated
Reagent	Annual reagent cost	$ 98,105	$/yr	Eqn 2.47
	Natural gas consumption	5	MMBtu/hr	Estimated
$Cost_{nat\ gas}$	Natural gas unit fee	$ 6.00	$/MMBtu	Estimated
Gas	Natural gas costs	$ 229,408	$/yr	Calculated
	Electrical power consumption	167.38	kW	Eqn 2.48
$Cost_{power}$	Electrical power unit fee	$0.065	$/kW	Estimated
Power	Electrical power costs	$83,194	$/yr	Eqn 2.49
$CC_{replace}$	Cost of catalyst, scaled to 2011dollars (38% inflation rate assumed)	$ 331.20	$/ft^3	Page 2-43
Catalyst	Catalyst replacement cost	$ 206,218.82	$/catalyst life	Eqn 2.5
Y	Life of catalyst, catalyst deactivation exacerbate due to high SO_2 conc.	3	yr	Estimated
n	Life of SCR system	20	yr	Page 2-48
i	Interest rate	8.5%		Corp BB rating
FWF	Future worth factor	0.31		Eqn 2.52
CRF	Capital Recovery Factor	0.11		Eqn 2.55

CAPITAL COSTS (Excluding Site Preparation and Building Costs)			
1) DIRECT PURCHASE EQUIPMENT COSTS (PEC)	**$**	**5,165,805**	
a) Equipment cost, adjusted for inflation (38% assumed)	$	4,377,801	Eqn 2.36
$f(h_{SCR})$	$	166.90	Eqn 2.37
$f(NH_3)$	$	(21.84)	Eqn 2.38
f(new)	$	(1,004.64)	Eqn 2.40
$f(VOL_{catalyst})$	$	618,656	Eqn 2.43
b) Instrumentation	$	437,780	0.1 x EC
c) Sales tax	$	131,334	0.03 x EC
d) Freight	$	218,890	0.05 x EC
2) DIRECT INSTALLATION COSTS (DIC)	**$**	**1,808,032**	
a) Foundation and supports	$	516,580	0.1 x PEC
b) Handling and erection	$	1,033,161	0.2 x PEC
c) Electrical	$	51,658	0.01 x PEC
d) Ducting	$	51,658	0.01 x PEC
e) Insulation and painting	$	51,658	0.01 x PEC
f) Stack modifications	$	103,316	0.02 x PEC
3) DIRECT CONTINGENCY	**$**	**516,580**	**0.1 x PEC**
TOTAL DIRECT CAPITAL COSTS (DC)	**$**	**7,490,417**	
4) OTHER INDIRECT CAPITAL COSTS (INSTALLATION)	**$**	**1,911,347.82**	
a) Engineering	$	516,580	0.1 x PEC
b) Construction and field expenses	$	258,290	0.05 x PEC
c) Contractor fees	$	516,580	0.1 x PEC
d) Start-up	$	103,316	0.02 x PEC
e) Performance test	$	516,580	0.1 x PEC
5) INDIRECT CONTINGENCY	**$**	**382,270**	**0.2 x IC**
TOTAL INDIRECT CAPITAL COSTS (IC)	**$**	**2,293,617**	
TOTAL CAPITAL INVESTMENT (TCI)	**$**	**9,784,035**	**DC + IC**

ANNUAL COSTS			
1) DIRECT ANNUAL COSTS (DC)	**$**	**620,682**	**Eqn 2.45**
a) Annual Maintenance	$	146,761	Eqn 2.46
b) Annual Reagent Cost	$	98,105	Eqn 2.47
c) Annual Natural Gas Cost	$	229,408	Estimated
d) Annual Electricity Cost	$	83,194	Eqn 2.48
e) Annual Catalyst Cost	$	63,214	Eqn 2.50
2) INDIRECT ANNUAL COTS (IC)	**$**	**1,797,659**	
a) Overhead	$	372,409	60% Labor and Materials
b) Administrative Charges	$	195,681	2% of TCI
c) Property Taxes	$	97,840	1% of TCI
d) Insurance	$	97,840	1% of TCI
e) Capital Recovery	$	1,033,888	Eqn 2.54
TOTAL ANNUAL COST	**$**	**2,418,342**	**Eqn 2.56**

Cost Effectiveness, dollars per ton of NOx removed	**$**	**6,725**	**Eqn 2.58**

Incremental Annual Cost, dollars per year	**$**	**2,418,342**
Incremental NOx Reductions, tons per year		**141.78**
Incremental Cost per Ton NOx Reduced, dollars per ton	**$**	**17,057**

Facility Name	RBLC ID	Permit Date	Permit Number	Permit Valid (Yes/No)	Construction Date	Permitting Agency	Agency Contact	Phone Number	Boiler Size	Boiler Size Units	Equipment Description	Primary Fuel(s)	Secondary Fuel(s)
EPA RBLC DATABASE SEARCH RESULTS (New Construction, Biomass-Fired Utility and Large Industrial-Size Boilers/Furnaces >250 MMBtu/hr)													
Georgia Power Co., Mitchell Steam Generation Plant	GA-0140	12/3/2010	4911-095-0002-V-02-3	Yes, Permit Under Review Due to Boiler MACT	Not Started	Georgia Department of Natural Resources	Furqan Shaikh	(404) 363-7143	Unknown	--	Stoker Boiler	Biomass Fuels	ultra low sulfur diesel (ULSD) and/or biodiesel
Laidlaw Berlin Biopower	NH-0018	7/26/2010	TP-0054	Yes	Not Started	New Hampshire Department of Environmental Services	Todd Moore	(603) 271-6798	1,013	MMBtu/hr	Babcock & Wilcox Bubbling Fluidized Bed Boiler	wood fuel, including whole tree chips	ultra low sulfur diesel (ULSD)
NRG Energy Montville Power	CT-0156	4/6/2010	107-0056	Yes	Not Started	Connecticut Department of Environmental Protection	Kevin O'Neill	(860) 424-4152	600	MMBtu/hr	Vibrating Grate Stoker Boiler	untreated wood, clean urban wood wastes and forest residues	ultra low sulfur diesel (ULSD) and/or natural gas
Boise Cascade Corp, Boise White Paper	AL-0250	3/23/2010	102-0001	Yes	2010	Alabama Department of Environmental Management	Scott Sanders	(334) 271-7861	435	MMBtu/hr	Stoker Boiler	Wood	Natural gas for start-up
Lindale Renewable Energy	TX-0553	1/8/2010	PSDTX1184	Yes, Extension	Not Started	Texas Commission on Environmental Quality	Kate Stinchcomb	(512) 239-1583	674	MMBtu/hr	Detroit Stoker Grate Boiler	green wood or green wood mixed with up to 50% construction and demolition wood wastes	B100 Bio-Diesel
Aspen Power, Lufkin Generating Plant	TX-0555	10/26/2009	81706	Yes	Under Construction	Texas Commission on Environmental Quality	Richard Hughes	(512) 239-1554	693	MMBtu/hr	Stoker Boiler	untreated wood waste	B100 Bio-Diesel
Clean Power Berlin	NH-0015	9/25/2009	TP-0033	Yes, TP Reissued	Not Started	New Hampshire Department of Environmental Services	Todd Moore	(603) 271-6798	1,013	MMBtu/hr	Wellons Wood-Fired Close Coupled Gasifiers (CCG)	wood chips and non-contaminated wood products	Natural gas for start-up
Concord Steam Corporation	NH-0015	2/27/2009	TP-0014	Yes, TP Reissued	Not Started	New Hampshire Department of Environmental Services	Todd Moore	(603) 271-6798	305	MMBtu/hr	Riley Power Vibrating, Water-Cooled Grate, Stoker Boiler	wood chips and non-contaminated wood products	Natural gas for start-up

Facility Name	RBLC ID	Permit Date	Permit Number	Permit Valid (Yes/No)	Construction Date	Permitting Agency	Agency Contact	Phone Number	Boiler Size	Boiler Size Units	Equipment Description	Primary Fuel(s)	Secondary Fuel(s)
Yellow Pine Energy Company	GA-0132	12/3/2008 Amended 05/15/2009 Amended 09/8/2010	4911-061-0001-P-01-1	Yes, Facility has requested permit extension	Not Started	Georgia Department of Natural Resources	Furqan Shaikh	(404) 363-7143	1,450	MMBtu/hr	Circulating Fluidized Bed Boiler (based on March 4, 2010 modification)	Wood waste from timber harvesting (i.e. green tons)	low sulfur No. 2 fuel oil or propane for start-ups to 80% load. TDF up to 15% on a heat input basis, trial only
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery	FL-0301	12/6/2007	PSD-FL-389 (0510003-044-AC)	Yes	Unknown	Florida Department of Environmental Protection	David Read	(850) 717-9075	738	MMBtu/hr	Stoker (Boiler No. 7)	Bagasse	Wood Chips
Koda Energy	MN-0074	8/23/2007	13900114	Yes	2007	Minnesota Pollution Control Agency	Troy Johnson	(651) 296-6300	308	MMBtu/hr	Suspension Grate (Stoker) Biomass Boiler No. 3	Biomass Fuels	Natural gas
Simpson Tacoma Kraft Co.	WA-0335	5/22/2007	PSD-06-02	Yes	Unknown	Washington Department of Ecology	Robert Burmark	(360) 407-6812	595	MMBtu/hr	Hog Fuel (Stoker) Boiler	Wood waste (including cardboard)	WWTP Sludge with No. 6 Oil
Smurfit Stone Container Corp, Stevenson Mill	AL-0223	7/14/2006	705-0014-X015	Yes	Originally 1997	Alabama Department of Environmental Management	Scott Sanders	(334) 271-7861	620	MMBtu/hr	Traveling Grate Stoker	Wood Waste	Unknown
ADM, Northern Sun	ND-0022	5/1/2006	PTC06004	Yes	1989	North Dakota Department of Health	Lou Dendy, Permit Gary Kline, Testing	(701) 328-5188	280	MMBtu/hr	Spreader Stoker	Biomass Fuels	Unknown
Biomass Energy, South Point Biomass Generating	OH-0307	4/4/2006	07-00534	Yes, Permit Extended	Not Started	Ohio Environmental Protection Agency	Dave Morehart	(614) 644-3601	318	MMBtu/hr	Stoker	Wood	
Boise Cascade Corp, Wallula Mill	WA-0337	2/1/2006	PSD-01-07 Amendment 1	Yes	Constructed	Washington Department of Ecology	Robert Burmark	(360) 407-6812	343	MMBtu/hr	Hog Fuel Boiler	Wood/Bark	Natural gas up to 40%
Sierra Pacific Industries, Skagit Co. Lumber Mill	WA-0327	1/25/2006	PSD 05-04	Yes	Constructed	Washington Department of Ecology	Robert Burmark	(360) 407-6812	430	MMBtu/hr		Bark and Waste Wood	Natural gas for start-up
Potlatch Corporation, Ozan Unit	AR-0083	7/26/2005	0117-AOP-R4								Hog Fuel Boiler		
Darrington Energy	WA-0329	2/11/2005	PSD 03-04	No	Not Constructed	Washington Department of Ecology	Robert Burmark	(360) 407-6812	403	MMBtu/hr		Wood Waste	Oil (<0.05% sulfur) for start-up
Inland Paperboard and Packaging, Bogalusa Mill	LA-0188	11/23/2004	PSD-LA-698						787.5	MMBtu/hr	Stoker Boiler	Fuel Oil (568.75 MMBtu/hr)	Fiber (OCC) Rejects (374 MMBtu/hr)

Facility Name	RBLC ID	Permit Date	Permit Number	Permit Valid (Yes/No)	Construction Date	Permitting Agency	Agency Contact	Phone Number	Boiler Size	Boiler Size Units	Equipment Description	Primary Fuel(s)	Secondary Fuel(s)
Public Service of New Hampshire, Schiller Station	NH-0013	10/25/2004	TP-B-0501	Yes	2006/2007	New Hampshire Department of Environmental Services	Todd Moore	(603) 271-6798	720	MMBtu/hr	Circulating Fluidized Bed Boiler (Alstom with Coen Burners)	Biomass Fuels (720 MMBtu/hr)	Coal (635 MMBtu/hr)
Inland Paperboard and Packaging, Rome Linerboard Mill	GA-0114	10/13/2004	2631-115-0021-V-01-4	Yes	Converted	Georgia Department of Natural Resources	Heather Cottrell	(404) 362-4843	856	MMBtu/hr	Fluidized Bed Boiler (converted from existing Recovery Furnace 3)	Bark, wood residue, waste wood	WWTP Sludge, TDF, Fuel Oil and NCG
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery	FL-0257	11/18/2003	PSD-FL-333	Yes	Unknown	Florida Department of Environmental Protection	David Read	(850) 717-9000	936	MMBtu/hr	Spreader Grate (Stoker) Boiler No. 8	Bagasse	Distillate Oil (<0.05% sulfur)
Sierra Pacific Industries, Aberdeen Division	WA-0298	10/17/2002	PSD-02-02						310	MMBtu/hr	Spreader Stoker Boiler	Waste Wood	
Meadwestvaco Kentucky, Wickliffe	KY-0085	2/27/2002	VF-01-002						631	MMBtu/hr		Bark, wood residue, waste wood	WWTP Sludge, Waste Oil and Natural Gas
S.D. Warren Co., Skowhegan, ME	ME-0021	11/27/2001	A-19-71-K-A							MMBtu/hr		Bark, wood residue, waste wood	Fuel Oils No. 6 and No. 2 TDF, others
District Energy, St. Paul	MN-0046	11/15/2001	12300063-001						550	MMBtu/hr		Wood	
Tri-Gen Biopower	GA-0117	5/24/2001	2631-039-0025-P-01-0	No, Plant Shutdown Oct 2002	N/A	Georgia Department of Natural Resources	Furqan Shaikh	(404) 363-7143	302.2	MMBtu/hr		Wood Waste and Papermill Sludge	

Facility Name	RBLC ID	Pollutant	Control Equipment	Control Efficiency	Basis	Primary Emission Limit	Primary Emission Limit Unit	Primary Emission Limit Averaging Period	Verified (Yes/No)	Notes
EPA RBLC DATABASE SEARCH RESUL	**EPA RBLC**									
Georgia Power Co., Mitchell Steam Generation Plant	GA-0140	CO	GCP		BACT	0.45	lb/MMBtu	30-day rolling	Unknown	Coal-fired Steam Generating Unit (155 MW) being converted to a biomass-fired stoker Steam Generating Unit (96 MW). Boiler permitted to burn biomass fuel, including clean wood chips (e.g. pine chips, hardwood chips, pallets and reels), whole tree chips (e.g. trees, shrubs, unmerchantable fuel wood, and thinnings), forest residues (e.g. tops, limbs and bark), manufacturer's residues (e.g. sawdust and sanders dust), and hulls (e.g. peanut and pecan hulls). Ultra low sulfur (i.e. <0.0015%) No. 2 fuel oil, or biodiesel or blend of previous two fuels may be burned for start-up and shutdown, and to assist in achieving peak load and flame stabilization.
		PM10, Filterable	ESP, Cyclone		BACT	0.04	lb/MMBtu	3-hour, every 12 months	Unknown	
		VOC	GCP		BACT	0.05	lb/MMBtu	3-hour, every 12 months	Unknown	
Laidlaw Berlin Biopower	NH-0018	CO	BFB Boiler Design and FGR		BACT	0.075	lb/MMBtu	calendar day	No	The maximum heat input rate of the boiler will be 1,013 million British Thermal Units per hour (MMBtu/hr) assuming fuel with a moisture content of 50%.The boiler will also be equipped with four oil fired burners for use during startup only. Each oil burner will have a maximum heat input rate of 60 MMBtu/hr.
		NOx	SCR		LAER	0.06	lb/MMBtu	30-day rolling	No	
		SO2	dry sorbent injection system		BACT	0.012	lb/MMBtu	stack test	No	
		SAM	dry sorbent injection system		BACT	0.002	lb/MMBtu	stack test	No	
		HCl	dry sorbent injection system		MACT	0.0008	lb/MMBtu	stack test	No	
		PM10, Filterable	Fabric Filter Baghouse		BACT	0.01	lb/MMBtu	stack test	No	
		PM2.5, Filterable	Fabric Filter Baghouse		BACT	0.01	lb/MMBtu	stack test	No	
NRG Energy Montville Power	CT-0156	NH3	N/A		State BACT	18	ppm		Unknown	Natural gas and No. 6 Oil-fired steam generating unit (82 MW) being converted to vibrating grate stoker wood biomass boiler to produce 40 MW, as well as maintaining ability to combust liquid fuel or natural gas to full 82 MW capacity, with a 7% annual capacity limit.
		CO	Oxidation Catalyst	70	BACT	0.1	lb/MMBtu	8-hour	No	
		NOx	RSCR	70	LAER	0.06	lb/MMBtu	24-hour	No	
		NOx	LNB		LAER	0.02	lb/MMBtu	24-hour	No	
		SOx	Low Sulfur Fuels		BACT	0.025	lb/MMBtu	3-hour	Unknown	
		PM, Total	Dry ESP and Cyclones	95	BACT	0.026	lb/MMBtu		No	
		VOC	Oxidation Catalyst	70	BACT	0.01	lb/MMBtu		No	
Boise Cascade Corp, Boise White Paper	AL-0250	NOx	LNB	60	BACT	0.3	lb/MMBtu	3-hour	**Yes**	
		VOC	GCP		BACT	0.03	lb/MMBtu	3-hour	**Yes**	
Lindale Renewable Energy	TX-0553	CO	GCP		BACT	0.31	lb/MMBtu	30-day rolling	Unknown	50 MW net power to grid using biomass fuels. The plant will burn between 54 and 73 tons per hour (tph) of biomass and will operate up to 8,760 hours/year. The plant is designed to burn 100% green wood or green wood mixed with up to 50% construction and demolition wood wastes and B100 Bio-Diesel will be used during startup.
		NOx	SNCR		BACT	0.15	lb/MMBtu	30-day rolling	Unknown	
		SOx			BACT	0.025	lb/MMBtu	30-day rolling	Unknown	
		HCl			BACT	0.019	lb/MMBtu	30-day rolling	Unknown	
		PM, Filterable	ESP		BACT	0.02	lb/MMBtu	30-day rolling	Unknown	
Aspen Power, Lufkin Generating Plant	TX-0555	NH3	N/A		BACT	15	ppmv@7% O2		Unknown	Aspen Power is proposing to install a 692.6 MMBtu/hr stoking grate wood waste derived fuel boiler which will drive a 45 MW steam turbine generator. The fuel will consist of untreated wood waste (primarily logging or lumber mill residue and wood products that have been shaped and/or assembled with only mechanical fasteners).
		CO	Oxidation Catalyst		Other	0.075	lb/MMBtu	30-day rolling	Unknown	
		NOx	SCR		Other	0.075	lb/MMBtu	30-day rolling	Unknown	
		SOx	None		BACT	0.025	lb/MMBtu	30-day rolling	Unknown	Per the agency, neighborhood opposition resulted in the voluntary installation of SCR for NOx control and an oxidation catalyst (if needed) for CO control. This boiler is under construction and no performance testing has been completed.
		HCl	None		BACT	0.02	lb/MMBtu	1-hour	Unknown	
		PM, Filterable	ESP		MACT	0.012	lb/MMBtu	30-day rolling	Unknown	
		PM, Total	ESP		BACT	0.025	lb/MMBtu	30-day rolling	Unknown	
		VOC			BACT	0.01	lb/MMBtu	30-day rolling	Unknown	
Clean Power Berlin	NH-0015	NOx	SCR	70	LAER	0.065	lb/MMBtu	30-day rolling	No	390 MMBtu/hr - Wood chips-equivalent to 40.75 tons per hour assuming average moisture content of 45% by weight. 90 MMBtu/hr from natural gas on boiler startups, at a maximum of 88,235 scf/hr.
Concord Steam Corporation	NH-0015	NOx	SCR	70	LAER	0.065	lb/MMBtu	30-day rolling	No	305 MMBtu/hr - Wood chips. 90 MMBtu/hr from natural gas on boiler startups.

Facility Name	RBLC ID	Pollutant	Control Equipment	Control Efficiency	Basis	Primary Emission Limit	Primary Emission Limit Unit	Primary Emission Limit Averaging Period	Verified (Yes/No)	Notes
Yellow Pine Energy Company	GA-0132	CO	BFB Boiler Design GCP		BACT	0.149	lb/MMBtu	30-day rolling	Unknown	Boiler can fire low sulfur distillate fuel or propane at S&S; can fire 95% metal free tire-derived fuels as supplemental fuels up to 15% on a MMBtu/hr basis on a trial basis only.
		NOx	SNCR and LNB	60	BACT	0.07	lb/MMBtu	30-day rolling	No	NOx emission limit modified from original BACT.
		SOx	Sorbent Injection	75	BACT	0.014	lb/MMBtu	30-day rolling	No	SO2 control modified from original BACT.
		HCl	Dry Scrubber System	75	MACT	0.006	lb/MMBtu	3 test run, every 12 months	No	
		PM10, Filterable	Fabric Filter Baghouse	99	BACT	0.01	lb/MMBtu	3 test run, every 12 months	No	
		PM10, Total	Fabric Filter Baghouse	99	BACT	0.018	lb/MMBtu	3 test run, every 12 months	No	
		VOC	BFB Boiler Design GCP	N/A	BACT	0.02	lb/MMBtu	3 test run, every 12 months	Unknown	
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery	FL-0301	NOx	Boiler Design		BACT	0.31	lb/MMBtu	3 test run	**Yes**	Project will add wood chips as a seasonal start-up fuel and to support minimal refinery operations during crop off season. Wood chips limited to an annual capacity factor of 25%.
Koda Energy	MN-0074	NOx	SNCR, LNB	37.5	BACT	0.25	lb/MMBtu		Unknown	Biomass consists of untreated wood, oat hulls, malt and grain by-products.
		PM	ESP, Cyclone		BACT	0.037	lb/MMBtu		Unknown	
Simpson Tacoma Kraft Co.	WA-0335	CO	OFA		BACT	0.35	lb/MMBtu	30-day rolling	Unknown	Permitted fuels include 89% wood waste (including recycled cardboard), 8% wastewater treatment sludge and 3% No. 6 fuel oil.
		NOx	OFA		BACT	0.2	lb/MMBtu	30-day rolling	**NO, Under Review**	The mill is located on Puget Sound and burns wood waste that contains some salt. Previous experience with SNCR ammonia injection at a similar mill (Kimberly Clark Everett) produced a persistent visible plume of ammonia chloride. WA therefore prefers a tight NOx limit based on proper combustion and OFA rather than SNCR at the Tacoma Mill.
		PM10, Filterable	ESP	99	BACT	0.02	lb/MMBtu	calendar day	**Yes**	
Smurfit Stone Container Corp, Stevenson Mill	AL-0223	SO2			BACT	93	lb/hr	3-hour	**Yes**	
		SAM			BACT	0.022	lb/MMBtu	3-hour	**Yes**	
ADM, Northern Sun	ND-0022	CO	GCP		BACT	0.63	lb/MMBtu		**Yes (Per Agency)**	Permitted fuels include hulls (sunflower and soybean hulls), biomass fuels, creosote-treated railroad ties and clean wood. Biomass fuels consis of approximately 70% to 95% hulls, 2.5% to 3% wax and 6% vegetable oil.
		NOx	Combustion Controls		BACT	0.2	lb/MMBtu	30-day rolling	**Yes (Per Agency)**	
		SO2			BACT	0.47	lb/MMBtu	24-hour	**Yes (Per Agency)**	
		PM	ESP		BACT	0.08	lb/MMBtu		**Yes (Per Agency)**	
Biomass Energy, South Point Biomass Generating	OH-0307	NH3			BACT	2.29	lb/hr		No	
		CO	Oxidation Catalyst	50	BACT	0.1	lb/MMBtu		No	
		NOx	SCR	80	State BAT	0.44	lb/MMBtu		No	
		SO2	SDA	20	State BAT	0.087	lb/MMBtu		No	
		HCl	SDA		BACT	0.0256	lb/MMBtu	fuel analysis	No	
		PM, Filterable	Fabric Filter Baghouse		BACT	0.0064	gr/dscf		No	
		Visible	Fabric Filter Baghouse		BACT	20	%		No	
		VOC	GCP		BACT	0.013	lb/MMBtu		No	
Boise Cascade Corp, Wallula Mill	WA-0337	CO	OFA		BACT	500	ppmvd		Unknown	Amendment 1 due to boiler not meeting NOx limit originally permitted. NOx limit raised to NSPS 0.3 lb/MMBtu.
		NOx	OFA		BACT	0.3	lb/MMBtu	30-day rolling	Unknown	
Sierra Pacific Industries, Skagit Co. Lumber Mill	WA-0327	CO			BACT	0.35	lb/MMBtu		Unknown	
		NOx	SNCR	48	BACT	0.13	lb/MMBtu		Unknown	
		SO2			BACT	0.025	lb/MMBtu	3-hour	Unknown	
		PM10, Filterable	ESP	99	BACT	0.02	lb/MMBtu	24-hour	Unknown	
		VOC	GCP		BACT	0.019	lb/MMBtu	1-hour	Unknown	
Potlatch Corporation, Ozan Unit	AR-0083	VOC	GCP		BACT	0.034	lb/MMBtu		Unknown	
Darrington Energy	WA-0329	CO	GCP		BACT	0.35	lb/MMBtu	24-hour	Unknown	The boiler is limited to waste wood from lumber manufacturing, whole trees or similar natural vegetation. Oil with a sulfur limit of 0.05% or less may be used for start-up or to maintain good combustions.
		NOx	SNCR		BACT	0.12	lb/MMBtu	24-hour	Unknown	
		PM10, Filterable	ESP		BACT	0.02	lb/MMBtu	24-hour	Unknown	
Inland Paperboard and Packaging, Bogalusa Mill	LA-0188	CO	OFA, GCP		BACT	0.6	lb/MMBtu	annual	Unknown	Boiler is permitted for 568.85 MMBtu/hr when combusting fuel oil and 374.0 MMBtu/hr when combusting secondary fiber (OCC) rejects.
		NOx	OFA, GCP, LNB		BACT	0.45	lb/MMBtu		Unknown	
		SO2	Fuel Oil Limit		BACT	1.54	lb/MMBtu		Unknown	Fuel oil limited to <10% annual capacity
		PM10, Filterable	Wet Scrubber		BACT	0.15	lb/MMBtu		Unknown	

Facility Name	RBLC ID	Pollutant	Control Equipment	Control Efficiency	Basis	Primary Emission Limit	Primary Emission Limit Unit	Primary Emission Limit Averaging Period	Verified (Yes/No)	Notes
Public Service of New Hampshire, Schiller Station	NH-0013	NH3			N/A	10	ppm@7% O2		**Yes (Per Agency)**	720 MMBtu/hr heat input when combusting biomass. Permitted wood fuel includes whole tree chips, untreated by-products or residue from forest products manufacturing operations, stump grindings or ground pallets. 635 MMBtu/hr heat input when combusting coal with a maximum sulfur content of 1.5 lb/MMBtu short term and 1.0 lb/MMBtu 3-month average. Coal is a backup fuel, but plant can fire coal up to 8,760 hours per year. All emission limits based on wood fuel use.
		CO	GCP		BACT	0.1	lb/MMBtu	24-hour	**Yes (Per Agency)**	
		NOx	SNCR/RSCR	65	Other	0.075	lb/MMBtu	24-hour	**Yes (Per Agency)****	
		SO2	Sorbent Injection	70	Other	0.02	lb/MMBtu	24-hour	**Yes (Per Agency)**	
		HCl	Sorbent Injection		MACT	0.02	lb/MMBtu	stack test	**Yes (Per Agency)**	**Agency reported that the facility has consistently met the Nox limit of 0.075 lb/MMBtu except during start-up. The agency is in the process of issuing a revised SSM limit of 0.15 lb/MMBtu over a multiple day average after a SSM event. The ammonia slip is monitored using a CEMS and the slip is consistently 3 to 5 ppm. The boiler is combusting wood only.
		PM10, Filterable	Fabric Filter Baghouse	99	MACT	0.025	lb/MMBtu		**Yes (Per Agency)**	
		VOC	GCP		N/A	0.005	lb/MMBtu	24-hour	**Yes (Per Agency)**	
Inland Paperboard and Packaging, Rome Linerboard Mill	GA-0114	CO	GCP		BACT	368	ppm@3% O2	30-day rolling	**Yes (Per Agency)**	Permitted fuels include bark, wastewater treatment sludge, tire-derived fuels, fuel oil, and NCG.
		H2S	Boiler		BACT	99% control			**Yes (Per Agency)**	H2S emissions from HVLC NCG in waste fuel
		PM10, Filterable	ESP		BACT	0.025	lb/MMBtu		**Yes (Per Agency)**	
		TRS	Boiler		BACT	99% control			**Yes (Per Agency)**	TRS emissions from HVLC NCG in waste fuel
		VOC	GCP		BACT	0.05	lb/MMBtu		**Yes (Per Agency)**	
U.S. Sugar Corporation, Clewiston Sugar Mill and Refinery	FL-0257	NH3			N/A	20	ppmvd@7% O2		No	Permitted fuels include bagasse and distillate oil (<0.05% sulfur by weight).
		CO	GCP		Other	0.38	lb/MMBtu	12-month rolling	No	
		NOx	SNCR	50	BACT	0.14	lb/MMBtu	30-day rolling	No	
		SO2	Fuel Limit		BACT	0.06	lb/MMBtu		No	
		Acid Mist/Gases	Fuel Limit		BACT	0.004	lb/MMBtu	SO2 as surrogate	No	
		PM	ESP, Cyclone	99	BACT	0.026	lb/MMBtu		No	
		Visible	ESP, Cyclone		BACT	20	%		No	
		VOC	GCP		BACT	0.05	lb/MMBtu		No	
Sierra Pacific Industries, Aberdeen Division	WA-0298	CO	GCP		BACT	0.35	lb/MMBtu	24-hour	No	
		NOx	SNCR		BACT	0.15	lb/MMBtu	24-hour	No	
		NOx	SNCR		BACT	0.1	lb/MMBtu	annual	No	
		PM	ESP		BACT	0.02	lb/MMBtu	24-hour	No	
Meadwestvaco Kentucky, Wickliffe	KY-0085	NOx			BACT	0.4	lb/MMBtu		No	Permitted fuels include bark/wood waste, wastewater treatment sludge, waste oil and natural gas. Boiler is an incineration point for NCG vent streams. Maximum hourly heat is limited to 463 MMBtu/hr when firing 55% moisture content wood residue; 634 MMBtu/hr when firing 30% moisture content wood residue; and 631 MMBtu/hr when firing any optimum mixture of wood residue and natural gas.
		SO2			BACT	0.8	lb/MMBtu		No	
		PM	ESP		BACT	0.1	lb/MMBtu		No	
		Visible	ESP		BACT	20	%		No	
S.D. Warren Co., Skowhegan, ME	ME-0021	CO	GCP		BACT	0.4	lb/MMBtu		No	Permitted fuels include bark, wood/wood waste, dewatered mill sludge, No. 2 fuel oil, No. 6 fuel oil, tire-derived fuels, waste papers, reclaimed specification and off-spec waste oil.
		NOx	SNCR		BACT	0.2	lb/MMBtu		No	
		SO2	Wet Scrubber		BACT	0.27	lb/MMBtu		No	
		PM	ESP	99	BACT	0.03	lb/MMBtu		No	
		VOC	GCP		BACT	0.007	lb/MMBtu		No	
District Energy, St. Paul	MN-0046	CO	GCP		BACT	0.3	lb/MMBtu		No	Permitted fuels include bark, wood fiber sludge and fossil fuels.
		NOx	SNCR		BACT	0.15	lb/MMBtu		No	
		PM	ESP, Cyclone		BACT	0.03	lb/MMBtu		No	
Tri-Gen Biopower	GA-0117	CO	GCP		BACT	0.3	lb/MMBtu		Unknown	Boiler limited to firing 400,000 ton/yr bagasse and 500,000 gallons per year No. 6 fuel oil. Total heat input not to exceed 2,880,000 MMBtu/yr. Heat input for boiler when co-firing with fuel oil is 530 MMBtu/hr (255 MMBtu/hr from fuel oil and 305 MMBtu/hr from bagasse).
		PM10, Filterable	ESP, Wet Scrubber		BACT	0.026	lb/MMBtu		Unknown	