6.0 Demonstration of Best Achievable Control Technology

6.1 Introduction

Under PSD regulations, a new or modified "major source" is required to apply BACT for any pollutant emitted in "major" or "significant" amounts. As discussed in Section 3.0, the proposed modification will have the potential to emit NO_X, CO, VOC, PM-10, and SO_2 in "significant" quantities. A BACT analysis is therefore required for these pollutants. The purpose of this review is to demonstrate that the air pollution control measures to be utilized for the proposed modification represent BACT as defined by Section 169 of the Clean Air Act:

"An emission limitation (including a visible emissions standard) based on the maximum degree of reduction of each pollutant subject to regulations under the Act which would be emitted from any proposed major stationary source or major modification, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, economic impacts and other costs, determines is achievable for such source or modifications through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment of innovative fuel combination techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61."

Both the EPA and GA EPD have indicated that the demonstration of BACT described above should follow the "top-down" approach. This approach will ensure that a BACT demonstration consider the most stringent level of control technology available. If it can be shown that this level of control is technically, economically, or environmentally infeasible, then the next most stringent level of control is determined and similarly evaluated. The process continues until the BACT level under consideration cannot be eliminated by any substantial or unique economic or environmental objectives. For this project, the only sources of emission for which BACT will apply will be FB boiler(s), the auxiliary boiler, material storage and handling, and the cooling tower.

The purpose of this section is to demonstrate that the proposed emission control systems and methods of operation will be representative of BACT. The following sections present the control technology alternatives available and a demonstration of BACT for each.

A BACT analysis is presented for each emission unit that contributes to the total emissions of a pollutant. Additionally, a BACT analysis is presented for material storage and handling processes and the cooling tower.

6.2 Methodology

The requirement to conduct a BACT analysis and determination is set forth in section 165(a)(4) of the Clean Air Act and in federal regulations 40 CFR 52.21(j). EPA has developed a process for conducting BACT analyses. This method is referred to as the "top-down" method. The steps to conduct a "top-down" analysis are listed in EPA's "New Source Review Workshop Manual," Draft, October 1990:

- Step 1 – Identify All Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Controls and Document Results
- Step 5 – Select BACT

6.3 Fluidized Bed (FB) Boiler

As discussed previously, the proposed Facility will install and operate FB boiler(s) with a heat input rating of 1529 MMBtu/hr. The heat input is from either 100% biomass or a biomass/fossil fuel mix whereby up to 15% of the heat input to the FB boiler can be derived from burning coal, pet coke, or TDF on an hourly or annual average basis.

6.3.1 Nitrogen Oxides

Nitrogen Oxides (NO_X) are formed during combustion by two mechanisms; thermal formation ("Thermal NO_X") and fuel formation ("Fuel NO_X"). Thermal NO_X results from high temperature oxidation of nitrogen. In this mechanism, elemental nitrogen and oxygen in the combustion air combine within the high temperature environment of the combustion zone. As its name implies, thermal NO_X formation is primarily dependent on combustion temperature. Thermal NO_X formation increases exponentially with temperature, and becomes significant at temperatures above 2,800 °F. Fuel NO_X results from the direct oxidation of organic nitrogen compounds in the fuel. As a result, nitrogen levels in fuel have a direct impact on NO_X formation.

EPA's RACT/BACT/LAER Clearinghouse (RBLC) database was reviewed to identify technologies that could potentially be used to control NO_X emissions from biomass-fired fluidized bed or similar boilers. Information obtained from the RBLC database for Circulating Fluidized Bed (CFB) boilers indicates that combustion control and/or selective non-catalytic reduction (SNCR) technologies are and have been used to control NO_X emissions from fluidized bed boilers (see Appendix B, Table B-1). Although no bubbling FB boilers were identified in the database, it is noted that bubbling and circulating FB boilers are very similar in design and performance, especially when the fuel mix is narrow as in this case. For the purposes of this assessment, control technologies were considered to be equally relevant and applicable to either of the FB boiler types. A broader review of the RBLC database also identified combustion controls and Selective Catalytic Reduction (SCR) technologies have been considered and used for the control of NO_X emissions from PC Coal and biomass-fired boilers (see Appendix B, Table B-7). The following is a discussion of the potential control technologies that are considered feasible for NO_X control from the proposed FB boiler and a discussion of their technical feasibilities.

Pre-Combustion NO_X Control Technologies

Fuel Selection. Nitrogen is one of the elements contained in biomass, coal, pet coke, and TDF. The amount of nitrogen in a particular fuel is variable. For biomass and TDF, the nitrogen content is generally less than 1 percent on a dry basis and for coal and pet coke is generally less than 2 percent. The boiler will normally be fired on up to 100% biomass, with the potential to fire up to 15% coal, pet coke or TDF by heat input. Since biomass has a lower nitrogen content than coal and pet coke. Fuel NO_X can be reduced by burning a secondary fuel that contains less nitrogen content like TDF. In practice, because the fossil fuel component is so small, the secondary fuel selection will be based on more significant parameters, such as sulfur content and fuel heating value, and in consideration of the economic and logistic factors associated with the delivery of the fuel to the site. Furthermore, the substitution of a secondary fuel that has less nitrogen content may cause an increase in other types of emissions.

Low NO_X Burners (LNB). Low NO_X burners limit NO_X formation by controlling both the stoichiometric and temperature profiles of the combustion process. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NO_X emissions during the combustion process.

Rotating Opposed Fire Air (ROFA). The ROFA design injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA differs from OFA in that ROFA utilizes a booster fan to increase the velocity of air to promote better mixing and to increase the retention time in the furnace. A modification of the ROFA process is RotaMix in which urea or ammonia is injected with ROFA.

Natural Gas Reburning (NGR). NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, thus creating a secondary (or reburn) fuel, natural gas, which is injected to produce a slightly fuel rich reburn zone. Overfire air is added above the reburn zone to complete burnout of the reburn fuel. As fuel gas passes through the reburn zone, part of the NO_X formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) and converted to molecular nitrogen.

Fuel Lean Gas Reburning (FLGR). FLGR, also known as controlled gas injection, is a process in which careful injection and controlled mixing of natural gas into the furnace exit region reduces NO_X. The gas is normally injected into a lower temperature zone than in NGR. Whereas NGR requires 15 to 20 percent of furnace heat input from gas and requires burnout air, the FLGR technology achieves NO_X control using less than 10 percent gas heat input and no burnout air. Less NO_X reduction is achieved with FLGR when compared with NGR.

Advanced Gas Reburning (AGR). AGR adds rich compound (typically urea or ammonia) downstream of the reburning zone. The reburning system is adjusted for somewhat lower NO_X reduction to produce free radicals that enhance the selective non-catalytic NO_X reduction. AGR systems can be designed in two ways: (1) non-synergistic, which is essentially the sequential application of NGR and selective non-catalytic reduction (i.e., the nitrogen agent is injected with a second burnout air stream). To obtain maximum NO_X reduction and minimum reagent slip in non-synergistic systems, the nitrogen agent must be injected so that it is available for reaction with furnace gases within a temperature zone around 1800°F.

Amine Enhanced Gas Injection (AEGI). AEGI is similar to AGR, except that burn out air is not used, and the selective non-catalytic reduction reagent and reburn fuel are injected to create local, fuel-rich NO_X reduction zones in an overall fuel-lean furnace. The fuel-rich zone exists in local eddies, as in FLGR, with the overall furnace in an oxidizing condition; however, the reduction reagent participates with natural gas (or other hydrocarbon fuel) in a NO_X reduction reaction.

Induced Flue Gas Recirculation (IFGR). IFGR recirculates boiler flue gas from the boiler outlet to the furnace where it is reintroduced into the combustion process. Fuel/air mixing in the combustion region is intensified by the recirculated flue gas when introduced into the flame during the early stages of combustion. This intensified mixing offsets the decrease in flame temperature and results in NO_X levels that are lower than those achieved without IFGR. The level of NO_X reduction is dependent upon the burner and furnace design. An additional benefit of IFGR is the potential to lower CO emissions.

Combustion Controls. As is the case with other types of boilers, combustion control (combustion air staging) is the most cost-effective means for reducing NO_X emissions from FB boilers. Combustion air staging is accomplished by introducing combustion air at two or more levels in the combustion section. Primary air is distributed through an air distributor plate to fluidize the bed. The amount of primary air is maintained below the stoichiometric requirement. Thus, the fuel is initially combusted under rich conditions, which inhibit the formation of NO_X in two ways. First, the amount of oxygen available to oxidize fuel and nitrogen is minimized, minimizing the potential for the oxidation reaction. Second, the concentration of hydrogen-free radicals is increased. These radicals react with some of the NO_X reducing it to nitrogen.

Secondary air is introduced several levels above the bed in the freeboard area. The secondary air brings the total amount of combustion air up to the level needed to achieve good combustion efficiency and minimize emissions of CO and hydrocarbons. The amount of secondary combustion air and the time between primary and secondary air injection is important for minimizing NO_X formation. There are practical limits on how much secondary air can be introduced and how high in the freeboard area the secondary air can be introduced without reducing combustion efficiency, causing corrosion, and lowering steam temperature. The effectiveness of NO_X reduction from combustion air staging is deceased by incomplete combustion, which results in high levels of unburned carbon, CO, and hydrocarbons. Incomplete combustion also decreases the combustion efficiency, increases the amount of fuel consumed, and increases the solid waste volume due to the increased carbon content of the ash.

Post-Combustion NO_X Control Technologies

Selective Catalytic Reduction. SCR is a control technique that uses ammonia to react with the NO_X in the flue gas at the appropriate temperature in the presence of a catalyst to form water and nitrogen. SCR has two well-documented environmental impacts associated with it, ammonia emissions (sometimes called ammonia slip) and disposal of spent catalyst. Some ammonia emissions from an SCR system are unavoidable because of imperfect distribution of the reacting gases, and ammonia injection control limitations as well as a partially degraded catalyst that results in an incomplete reaction of the available ammonia with NO_X. The NO_X removal efficiency of an SCR system depends on the ratio of ammonia to NO_X. Therefore, increasing the amount of ammonia injected increases the control efficiency but also increases the amount of unreacted ammonia that is emitted to the atmosphere. Ammonia emissions from a well-controlled SCR system can likely be limited to 10 ppmv or less. Ammonia emissions are of concern, because ammonia is a significant contributor to regional secondary particulate formation and visibility degradation. In this case reduced NO_X emissions as an environmental benefit would be traded for increased ammonia emissions as an environmental cost.

The other environmental impact associated with SCR is disposal of the spent catalyst. Some of the catalyst used in SCR systems must be replaced every three to five years. These catalysts contain heavy metals including vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. This must be addressed when handling and disposing of the spent catalyst.

For a FB boiler, the SCR system would have to be located between the last convection section and the economizer, where optimal temperatures are present. Proper placement of the catalyst would significantly increase the cost of the boiler because the convective heat transfer area would have to be divided. SCR also affects the overall plant operation, because NH_3 and SO_3 in the flue gas react to form ammonium sulfate and bisulfate upstream of other environmental controls and flue gas handling equipment. Ammonium salt deposition is known to damage these controls and equipment and frequent cleaning is necessary, resulting in increased maintenance costs and unit down time. Additionally, because the SCR system is located upstream of the economizer and air heater, any changes to the boiler operations, such as increased load or excess air, will alter flue gas temperatures at the catalyst bed and can significantly affect both boiler and SCR performance. Important operating and design factors associated with SCR include catalyst deactivation, problems with unreacted SO_3 and NH_3, and process control limitations.

Catalyst deactivation is the loss of active catalyst sites necessary to promote the NH_3/NO_X reaction. Catalyst deactivation primarily occurs via four mechanisms: poisoning, fouling, thermal degradation, and mechanical losses. Because the SCR system would also be located upstream of a baghouse, mechanical losses and fouling have the potential to be significant problems with catalyst life due to the high dust/particulate load in the flue gas. The catalyst may be permanently poisoned as a result of metals and trace elements in the fuel. These compounds react with the active acid sites on the SCR catalyst surface, thus poisoning the catalyst. The ash material from fluidized bed boilers using limestone injection for SO_2 control typically contains 20 to 30 percent calcium oxide.

Selective Non-Catalytic Reduction. Similar to SCR, SNCR is a post-combustion control method. With the SNCR method a reagent, usually aqueous ammonia or urea, is injected into the hot thermal oxidizer zone just past the combustion zone. The reaction of this reagent with the NO_X present in the products of combustion is driven by the high temperatures within the combustion chamber. No catalyst is used with the SNCR method. The SNCR method is temperature dependent and has a very small temperature window.

The performance of SNCR is sensitive to flue gas temperature because optimal NO_X reduction occurs in a limited temperature window. In addition, adequate residence time at this temperature is necessary to complete the reactions. Flue gas temperatures fluctuate in the bed, the solids disengagement zone, and in the bypass sections of the fluidized bed boilers when there are changes in boiler load, fuel consumption, and combustion air temperature or flow. Because of this variability, the flue gas at the reagent injection point will not always be at the optimum temperature for NO_X reduction.

Below the SNCR operating temperature range, the NH_3/NO_X reaction will not occur, and the unreacted NH_3 will either be emitted as NH_3 slip, or it will react with SO_3 to form ammonium salts, or will be incorporate in the ash. Above the optimal temperature, the amount of NH_3 that oxidizes to NO_X increases and the NO_X reduction performance deteriorates rapidly. At temperatures at or above 1,900°F, unreacted NH_3 emissions decrease due to the NH_3 oxidation to NO_X. At temperatures at or below 1,800°F, unreacted NH_3 emissions increase. Maximum NO_X removal and minimum NH_3 slip can be achieved by injecting urea at 1,900°F.

Fluidized bed boilers typically operate with bed temperatures in the range of 1,500 to 1,600°F to maximize in-bed SO_2 control and limit thermal NO_X formation. This lower operating temperature reduces uncontrolled NO_X emissions relative to a PC coal boiler. For boilers requiring high (90 percent or higher) SO_2 removal using limestone injection, bed and solids disengagement section temperatures are below optimal for high NO_X reductions and low NH_3 slip using SNCR. However, in this case, because of the high biomass fuel usage, in-bed SO_2 removal is not much of a factor. Therefore, the FB boiler with SNCR may not be able to achieve the highest end potential NO_X reductions; biomass fuel (i.e. lower fuel nitrogen), lower boiler temperature and higher ammonia slip compensate to achieve a very low NO_X emission level on a cost-effective basis.

An important operating concern with SNCR is the reaction of SO_3 and unreacted NH_3 in the flue gases to form ammonium sulfate ($(NH_4)_2SO_4$) and ammonium bisulfate ((NH_4HSO_4). During combustion, a small percentage of SO_2 will be oxidized to SO_3. The SO_3 reacts with free NH_3 and water to form ammonium sulfates. Ammonium sulfates can condense on the cold end of the air heater and cause fouling. These deposits can cause a significant pressure drop across the air heater. Unfortunately, air soot blowing is often ineffective at removing the ammonium salt deposits. As a result, water washing is often necessary to remove the sticky, water-soluble material. Therefore, the boiler's air heater must be constructed of materials that can tolerate possible corrosion by the liquid waste and must be designed to accommodate water washing. Since the air heater must be cleaned with the boiler off-line, ammonium salt deposits can cause unplanned outages.

Ammonium sulfates can also cause fouling of baghouse fabric filters. These deposits can cause a significant pressure drop across the baghouse. As the pressure drop increases, the boiler capacity will reduce because the boiler fans will not be able to maintain design combustion air flows at the higher baghouse pressure drop.

Hybrid Selective Reduction (HSR). HSR is a combination of SNCR and SCR that is designed to provide the performance of full SCR with significant lower costs. In HSR, a SNCR system is used to achieve some NO_X reduction and to produce a controlled amount of ammonia slip that is used in a downstream in-duct SCR reactor for additional NO_X reduction.

$SCONO_X$. $SCONO_X$ is catalyst technology developed by Goal Line Environmental Technologies. The technology uses precious metal catalyst to simultaneously convert NO_X and CO to CO_2, H_2O, and N_2. The catalyst must be periodically removed from service for regeneration. This requirement necessitates multiple catalyst sections and additional ductwork and dampers for isolation. Hydrogen diluted with steam is used to regenerate the catalyst and produce a stream of H_2O and N_2 that is vented to the stack.

$THERMALONO_X$. The $THERMALONO_X$ technology has been developed by Thermal

Engineering International as an option for the control of NO_X emissions. The technology is based on the oxidation of NO to NO_2 and then dissolving the NO_2 in water. The THERMALONO_X technology is intended for use with a wet flue gas desulfurization (FGD) system used for SO_2 emission control. The NO oxidation is accomplished by injecting elemental phosphorous into the flue gas stream in a gas reactor installed upstream of the wet FGD absorber. The NO_2 becomes dissolved in the wet FGD absorber and can be removed as elemental N_2 or various phosphate compounds that may be used as fertilizer and/or animal food additive.

Electro-Catalytic Oxidation (ECO). ECO is a multi-pollutant control technology that simultaneously controls PM, SO_2, and NO_X along with mercury and hydrochloric acid. The Powerspan Corporation is the developer of the ECO technology. The ECO process includes a conventional dry electrostatic precipitator followed by a reactor that oxidizes the gaseous pollutants. A wet electrostatic precipitator then captures the oxidized pollutants.

Pahlman Process. The Pahlman process is a multi-pollutant control technology that simultaneously controls NO_X and SO_2. Enviroscrub Technologies, the developer of the Pahlman technology, has not been willing to release much information regarding the technology but it has advertised that the technology does not require catalyst or ammonia to accomplish emission reduction.

Control Technology Ranking

The boiler will be primarily fired on biomass. The type of secondary fuel used in the boiler will be selected on the basis of the cost of the fuel delivered to the site and on significant fuel characteristics, such as sulfur content and heating value, each of which strongly affects the design and cost of the boiler and air pollution control equipment. Because nitrogen is present in biomass, coal, pet coke, and TDF only in small amounts and there are many other means available to control NO_X emissions, the selection of fuel on the basis of nitrogen content in favor of the more important parameters listed above is not reasonable. For these reasons, selection of a fuel for the purpose of controlling NO_X is considered technically infeasible and will not be considered further in this application.

Low NOx Burners represent a mature technology for the reduction of NO_X formation during combustion. LNB's are available from numerous vendors that are willing to offer performance guarantees. Due to their cost effectiveness, LNB's are expected to be furnished with a new boiler regardless of other post-combustion NO_X emission reduction technologies employed and will be considered in combination with other NO_X reduction technologies.

ROFA and Rotamix are not mature technologies ready for commercial installation. They have only one commercial installation on a bituminous unit in which ROFA was installed in 2000 and modified for Rotamix in 2002. Recent literature on the process discusses only the one installation and does not provide compatibility with biomass, sub-bituminous coal, pet coke, and TDF firing. For these reasons, ROFA and Rotamix are considered technically infeasible and will not be considered further in this application.

NGR has been demonstrated to reduce NO_X emissions by 39 to 67 percent on several existing coal-fired boilers in applications ranging from 33 MW to 600 MW in the United States and up to 800 MW overseas. However, the combustion of natural gas in the reburn zone is not consistent with the project objective of primarily combusting biomass (renewable energy) and the absence of a natural gas pipeline in the area to supply natural gas. In addition, NGR is not listed as a control device for NO_X emissions from either biomass or coal-fired boilers in the RBLC database. Therefore, NGR is considered technically infeasible and will not be considered further in this application.

FLGR has been demonstrated to reduce NO_X emissions by 33 to 45 percent on several existing coal-fired boilers. The most recent application has been part of a combination FLGR and SNCR demonstration on a 198 MW coal-fired boiler. However, the combustion of natural gas in the furnace exit region is not consistent with the project objective of primarily combusting biomass (renewable energy). In addition, FLGR is not listed as a control device for NO_X emissions from either biomass or coal-fired boilers in the RBLC database. Therefore, FLGR is considered technically infeasible and will not be considered further in this application.

AGR has been applied to a 105 MW coal-fired boiler in the United States and a 285 MW coal-fired boiler in Europe. The projects demonstrated NO_X emissions reductions range from 50 to 76 percent; however ammonia slip in one application could not be reduced below

10 ppm. In the non-synergistic scenario, natural gas is injected in the reburning zone. In the synergistic scenario, the nitrogen agent is injected in the furnace gas around a temperature of 1800°F. This temperature is significantly higher than the expected boiler exit temperature and the NO_X removal efficiency will be greatly degraded at the lower temperature. In addition, AGR is not listed as a control device for NO_X emissions from either biomass or coal-fired boilers in the RBLC database. Additionally, the injection of natural gas in the furnace exit region is not consistent with the project objective of primarily combusting biomass (renewable energy). Therefore, AGR is considered technically infeasible and will not be considered further in this application.

AEGI has been demonstrated to reduce NO_X emissions by 30 to 73 percent during full-scale commercial applications. However, the combustion of natural gas is not consistent with the project objective of primarily combusting biomass (renewable energy). In addition, AEGI is not listed as a control device for NO_X emissions from either biomass or coal-fired boilers in the RBLC database. Therefore, AEGI is considered technically infeasible and will not be considered further in this application.

IFGR has been demonstrated as a NO_X reduction technology on smaller natural gas and oil-fired boilers. The applicability of this technology is limited due to the technical complications associated with recirculating the volume of hot, ash-laden flue gas that is generated by a FB boiler. The primary complication is the significant operations and maintenance issues that would result. In addition, IFGR is not listed as a control device for NO_X emissions form either biomass or coal-fired boilers in the RBLC database. Therefore, IFGR is considered technically infeasible and will not be considered further in this application.

Combustion Controls is a mature technology often utilized concurrently with the application of LNB. Combustion compliments the stoichiometric to sub-stoichiometric operation of LNB by providing the air required to complete fuel combustion and limit the formation of CO and VOC. Combustion Controls are expected to be furnished with a new boiler regardless of other post-combustion NO_X emission reduction technologies employed. For these reasons, combustion controls are considered technically feasible and will be considered in combination with other NO_X reduction technologies.

SCR is a proven technology for the reduction of NO_X emissions for typical boilers. However, FB boilers using limestone injection for SO_2 control typically contain 20 to 30 percent CaO. The high alkali metal and calcium content of the FB boiler ash is the major reason that SCR emission control technology has not been applied to FB boilers using limestone injection. The alkali metals and CAO are a catalyst poison and greatly reduce the life and effectiveness of the catalyst. Therefore, SCR is considered technically infeasible and will not be considered further in this application.

SNCR has been demonstrated in applications up to 600 MW to reduce NO_X emissions by 20 to 65 percent with ammonia slip less than 5 ppm. Therefore, SNCR is considered technically feasible.

HSR has been demonstrated to reduce NO_X emissions by 50 to 98 percent on a 320 MW coal-fired boiler. It is possible the technology can be scaled down to the size of the proposed project. However, HSR is not listed as a control device for NO_X emissions from either biomass or coal-fired boilers in the RBLC database. Therefore, HSR is considered technically infeasible and will not be considered further in this application.

$SCONO_X$ technology has not been demonstrated on the flue gas generated by coal combustion. It has only been demonstrated on gas-fired combined cycle power plants. In addition, the presence of SO_2 in the flue gas has the potential to poison the $SCONO_X$ catalyst, limiting its effectiveness and its useful life. $SCONO_X$ is not a suitable NO_X emissions control technology for the proposed boiler. Therefore, $SCONO_X$ is considered technically infeasible and will not be considered further in this application.

$THERMALONO_X$ technology has been installed and tested on flue gas from a coal fired-boiler. The purpose of the test was to demonstrate a NO_X reduction of 75 percent. The less than expected results of the first commercial operation prompted the host utility to halt testing of the technology until further laboratory testing could be completed. $THERMALONO_X$ is an immature technology and is not yet commercially available. Therefore, $THERMALONO_X$ is considered technically infeasible and will not be considered further in this application.

ECO was installed and successfully demonstrated as a pilot system to treat 2,000 to 4,000 SCFM of flue gas generated by a coal-fired boiler. The results of the demonstration showed a NO_X emission reduction of up to 90%. Powerspan is currently working with the host utility to install a larger 50 MW commercial demonstration facility. This demonstration facility was scheduled to be ready for commercial operation in early 2003; however, no published results of the demonstration have been located. ECO is an immature technology and is not commercially available. Therefore, ECO is considered technically infeasible and will not be considered further in this application.

The Pahlman process has been demonstrated in small scale testing to remove in excess of 90 percent of the NO_X emissions and 99 percent of the emissions from the flue gas generated by coal-fired boilers. However, the trailer mounted demonstration system is capable of only treating approximately 1,000 SCFM of flue gas. Enviroscrub Technologies plans to have a larger unit available for commercial testing by the end of 2002, however, no published results of the demonstration have been located. The Pahlman process is an immature technology and is not commercially available. Therefore, Pahlman process is considered technically infeasible and will not be considered further in this application.

Based on the above discussion, there are two technically feasible NO_X control technologies for biomass, coal, pet coke, TDF-fired FB boilers – combustion controls or combustion controls with SNCR. Table 6-1 presents the NO_X BACT hierarchy. There are numerous examples of projects where SNCR in conjunction with combustion controls has been permitted as BACT with emission rates in the range of 0.07 – 0.15 lb/MMBtu. The proposed BACT for the FB boiler includes combustion controls and SNCR capable of achieving NO_X emissions of 0.10 lb/MMBtu.

SNCR represents the control system that will result in the lowest controlled NO_X emission rate. Based on a maximum heat input to the boiler of 1529 MMBtu/hr and 8,760 hours/year maximum operation, an SNCR system would reduce NO_X emissions from the boiler from approximately 1482 tpy (based on combustion control only) to approximately 670 tpy.

The installation of SNCR will increase the capital cost of the boiler. Capital costs associated with SNCR include the SNCR grid, ammonia injection system, and system instrumentation.

The SNCR system will also increase the annual operating costs of the boiler. Operating costs associated with the SNCR include ammonia usage and auxiliary power cost.

A summary of the capital costs and annual O&M costs associated with the SNCR control system is provided in Table 6-1. Detailed cost estimates are provided in Appendix C.

TABLE 6-1
FB Boiler NO_X Control Technology Cost Effectiveness Evaluation
Yellow Pine Energy
Clay County, Georgia

Control Technology	Total Installed Capital Costs	Total Annualized Costs	Annual Emission Reduction[a]	Cost Effectiveness[b]
SNCR	$10,513,775	$2,509,879	812	$3,090
Combustion Control	Base	Base		

[a] Tons/Year emissions based on 1529 MMBtu/hr boiler heat input, 8,760 hours of operation per year, combustion of 85% biomass and 15% fossil fuel. The controlled NO_X emission rate is identical for biomass, coal, pet coke, and TDF firing.
[b] $ per ton of pollutant removed.

Based on information available from vendors, an SNCR system will increase the cost of the boiler by approximately $10,513,775. Total annualized costs associated with the SNCR system, including ammonia, auxiliary power, capital recovery, and indirect operating costs are estimated to be approximately $2,509,879/year. Based on an annual reduction in NO_X emissions of 812 tpy (1,482 tpy – 670 tpy) compared to the combustion control alternative, the incremental cost effectiveness of the SNCR system would be approximately $3,090/ton. Based on the relatively small increase in annualized cost, Yellow Pine Energy feels it is appropriate to construct the boiler with combustion controls and a SNCR control system.

6.3.2 PM-10

Particulate matter less than 10 micrometers in diameter (PM-10) in the boiler is formed as a result of inert solids contained in the fuel, unburned fuel hydrocarbons, and byproducts of limestone injection, which agglomerate to form particles.

The RBLC database was reviewed to identify technologies used to control PM-10 emissions from FB boilers. Data from the RBLC for FB boilers indicates that fabric filter/baghouses and Electrostatic Precipitators (ESPs) are used to control PM-10 emissions from FB boilers (see Appendix B, Table B-2). A broader review of the RBLC database identified ESPs, wet scrubbers, mechanical collectors, and fabric filter/baghouses to control PM-10 emissions from biomass-fired boilers (see Appendix B, Table B-8). The following is a discussion of the potential control technologies and a discussion of their technical feasibility.

Fuel Selection. In some instances, particulate emissions can be reduced by substitution of one fuel with another fuel that has lower ash content. Combustion of a lower ash-containing fuel will result in less fly ash generation, hence, less PM-10 emissions. This determination must be made on a case-by-case basis with consideration of the economic and logistical factors associated with the delivery of a specific type of fuel. Furthermore, it must be considered that the substitution of a fuel that produces less PM-10 emissions may cause an increase in other types of emissions, or increase auxiliary power consumption and/or reagent consumption (limestone, ammonia. etc.).

Coal Cleaning. Coal cleaning will be discussed in detail in Section 5.3.3. In general, combustion of coal with less ash content will result in less fly ash generation and therefore, less PM-10 emissions.

Electrostatic Precipitators. ESPs are rarely used on FB boilers using limestone injection in a dry scrubber for SO_2 control because the use of a FGD-baghouse combination significantly increases the achievable SO_2 control while achieving comparable PM control. As the flue gas passes through the filter cake, additional SO_2 is removed by unreacted limestone and calcium oxide in the filter cake. Additionally, due to the high resistivity of the PM-10, which is predominately calcium oxide and calcium sulfate, a very large ESP plate area would be required to match the collection efficiency of a baghouse making the use of an ESP more costly than a baghouse. Use of an ESP before or after a baghouse would have no measurable benefit and would actually reduce the effective baghouse performance if placed upstream due to the very high particulate removal capability of the baghouse. However, if a FGD system were not included in the design, then a ESP may become applicable.

Wet Electrostatic Precipitator (WESP). A WESP operates in the same three-step process as a dry ESP: charging, collection, and removal. Unlike a dry ESP, the removal of particles from the collection electrodes is accomplished by washing of the collection surface using liquid, rather than mechanical rapping the collector plates. WESPs are more widely used in applications where the gas stream has a high moisture content, is below the dew point, or includes sticky particulate.

Wet Scrubbers and Mechanical Collectors. Wet scrubbers are not used for PM-10 control on fluidized bed boilers because of their lower overall collection efficiency, higher capital and operating costs, and the significant waste disposal and wastewater treatment issues that wet scrubbing entails. Wet scrubbers can not be used in series with fabric filter baghouses to improve on PM control efficiency. If a wet scrubber is used upstream of the baghouse, the saturation of the flue gas with water will result in plugging of the fabric filter due to the reaction of condensed moisture with the highly alkaline particulate matter. There is no benefit to putting a wet scrubber downstream of the baghouse since wet scrubbers have higher emission rates of PM than baghouse due to entrained water droplets that evaporate to particulates.

Mechanical collectors, such as cyclones, are used on FB boilers primarily for process reasons and secondary PM-10 control reasons. Cyclones permit un-combusted fuel to re-circulate back to the boiler, which is applicable when two dissimilar fuels are mixed is sizable proportions. For example, if biomass and coal were used 50/50, then given a single air velocity through the boiler, one would expect the less dense biomass to re-circulate, while the coal remained in the bed. In this case, biomass is 95% to 100% of the fuel mix by weight, so the air velocity would be tuned to combust biomass in the bed and a cyclone recirculation is not necessary. The solids disengagement section of the boiler is to separate the light fly ash material that exits the furnace and create the “bubbling bed” of uncombusted fuel. This bubbling process significantly improves overall combustion efficiency and uses limestone to efficiently capture acid gases such as SO_2. Secondly, the solids disengagement section reduces the particulate loading to the fabric filter baghouse reducing the frequency that the bags need to be replaced.

Fabric Filter Baghouses. Baghouses have a number of inherent advantages when used for control of fly ash from FB boilers using limestone injection for acid gas control. These advantages include:

- High PM-10 collection efficiencies as compared to other technologies,
- PM-10 collection capability is not sensitive to typical fuel sulfur and limestone injection variabilities,
- Additional control of SO_2 and other acid gases due to the filtration of the flue gas through the alkaline filter cake, and
- High trace metal control efficiencies.

In addition to very high levels of particulate matter and fine particulate matter control, the baghouse system also increases the performance of SO_2 control systems. The baghouse creates a filter cake on the bag as the flue gas passes through the filter cake additional SO_2 is removed by the filter cake. The filter cake will include unreacted alkaline materials. Depending on the operating conditions of the baghouse, the fabric filter may remove 15 – 30% of the total SO_2 removed. The same mechanism for reducing SO_2 emissions in the baghouse also helps reduce inorganic acid gas emissions. The baghouses are also more efficient at removing fine particulate matter and trace metals than other particulate matter control systems, including ESPs. The primary disadvantage of baghouses relative to ESPs is the higher pressure drop across the baghouse resulting in increased fan power requirements for the system.

Electro-Catalytic Oxidation (ECO). The discussion presented in Section 5.3.1 for ECO is applicable to PM-10 emissions.

Control Technology Ranking

The PM-10 removal efficiency of wet scrubbers, mechanical collectors, and ESPs would be less than the removal efficiency of fabric filtration for FB boilers using limestone injection for SO_2 control. Additionally, these other control technologies offer no measurable benefit in increased particulate mater control if placed upstream or downstream of a properly sized baghouse. As such, a fabric filter is the top performing control technology. The remainder of this section provides additional information on baghouse controls and identifies achievable emission levels.

A baghouse separates dry particles from the boiler flue gas by filtering the flue gas through a fabric filter. The components of a baghouse include fabric filters or "bags" as the filter media, a tubesheet to support the bags, a gas-tight enclosure, a mechanism to dislodge or clean accumulated dust from the bags, and a hopper to collect accumulated fly ash. The flue gas enters the lower portion of the baghouse and passes through the bags with the particulate from the flue gas collecting on either the inside or the outside of the bags depending on the cleaning technique. Baghouses are compartmentalized to allow cleaning of one compartment at a time and to provide for maintenance and repair. When the pressure drop across a compartment increases to a preset limit, due to buildup of ash on the bags, the filter cake collected on the bag is removed by placing that compartment in the cleaning mode.

As the flue gas flows through the fabric filter, a layer of accumulated fly ash, referred to as the "filter cake", builds up on the fabric filter. The primary filtering media is the filter cake, rather than the fabric itself. As this layer of ash grows, the pressure drop across the bag increases until a maximum set point is achieved. At this point, the bag is cleaned. The evolution of baghouse design has included several methods for cleaning the bag, including reverse air, reverse air with mechanical shakers, and pulse jet. In each of these baghouse types, the particulate removed from the bags by the cleaning process is collected in the hoppers below the filter bags.

There are numerous examples of projects where fabric filter baghouses have been permitted as BACT with emission rates in the range of 0.010 – 0.25 lb/MMBtu. Additionally, the Longleaf Energy Associates pulverized coal boilers were recently permitted with fabric filter baghouses as BACT with an emission rate of 0.033 lb/MMBtu. The proposed BACT for the FB boiler is fabric filter baghouses capable of achieving 99 percent removal and a PM-10 emissions of 0.033 lb/MMBtu.

A summary of the capital costs and annual O&M costs associated with the fabric filter/baghouse control system is provided in Table 6-2. Detailed cost estimates are provided in Appendix C.

TABLE 6-2
FB Boiler PM-10 Control Technology Cost Effectiveness Evaluation
Yellow Pine Energy
Clay County, Georgia

Control Technology	Total Installed Capital Costs	Total Annualized Costs	Annual Emission Reduction[a]	Cost Effectiveness[b]
Baghouse @ 0.033 lb/MMBtu	11,426,250	2,819,423	21,879	129

[a] Tons/Year emissions based on 1529 MMBtu/hr boiler heat input, 8,760 hours of operation per year. The controlled PM-10 emission rate is identical for biomass, coal, pet coke, and TDF firing.
[b] $ per ton of pollutant removed.

Based on information available from vendors, a baghouse system will increase the cost of the boiler by approximately $11,426,250. Total annualized costs associated with the baghouse system, maintenance labor and materials, auxiliary power, bag replacement, capital recovery, and indirect operating costs are estimated to be approximately $2,819,423/year. Based on an annual reduction in PM-10 emissions of 21, 879 tpy (22,100 tpy – 221 tpy) compared to the uncontrolled alternative, the incremental cost effectiveness of the baghouse system would be approximately $129/ton. Based on the relatively small increase in annualized cost, Yellow Pine Energy feels it is appropriate to construct the boiler with a baghouse system.

6.3.3 Sulfur Dioxide and Sulfuric Acid Mist

Sulfur Dioxide (SO_2) is formed during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. A portion of the sulfur is further oxidized to SO_3. At temperatures below approximately 600°F, sulfur trioxide readily combines with moisture in the flue gas or in the atmosphere to form H_2SO_4. These sulfur compounds are acidic and can be controlled using the same control technology.

The RBLC database was reviewed to identify technologies used to control SO_2 emissions from fluidized bed boilers. Data from the RBLC for Circulating Fluidized Bed (CFB) boilers indicates that lime spray dryer absorbers, wet and dry FGD technologies, lime injection, and fuel specification and particulate controls (ESP and fabric filter baghouse) are successfully used for the control of SO_2 and H_2SO_4 emissions from fluidized bed boilers (see Appendix B, Table B-3). The most prevalent technologies which have been used to control SO_2 emissions from biomass-fired boilers include wet and dry FGD technologies, lime injection, and fuel specification for the control of SO_2 (see Appendix B, Table B-9). The following is a discussion of the potential control technologies and a discussion of their technical feasibility.

Fuel Selection. The combustion of sulfur contained in the fuel is the primary source of SO_2 emissions from the combustion of biomass, coal, pet coke, and TDF. Firing fuel with lower sulfur content is a common method to lower SO_2 emissions, especially for boilers not equipped with flue gas desulfurization systems. The boiler will be primarily fired on biomass which has an extremely low sulfur content of approximately 0.02 percent. However, the use of flue gas desulfurization systems affords boiler operators flexibility in fuel purchasing with respect to the secondary fuels, which in this case will be coal, pet coke, and TDF.

Coal Cleaning. Coal normally contains significant quantities of inorganic elements such as iron, aluminum, silica, and sulfur. These elements occur primarily in ash-forming mineral deposits embedded within the coal but are also present to a lesser degree within the organic coal structure. Coal cleaning is a process that removes this mineral ash from the coal after it is removed from the ground. The relative amounts of contaminants, the manner in which they are included in the coal assemblage, and the degree to which they can be removed vary widely with different coals. The removal of this non-combustible material improves the heating value of the coal. The cleaning also removes some portion of sulfur, mostly pyretic sulfur, which may account for 10% to 80% of the total fuel sulfur content. The application and extent of coal cleaning depends on the particular mine and mining technique. Underground mines often clean coal prior to shipment, whereas surface mines tend to employ coal cleaning based upon the effectiveness of the overburden removal and thickness of the coal seam.

FB Boilers, Limestone Injection for SO_2 Control. The development of FB boiler technology has been driven largely by the need to reduce SO_2 and NO_X emissions from the combustion of high sulfur fuel such as coal. The major advantages to the FB boiler technology are the ability of controlling emissions of SO_2 to very low levels "in-situ" without post combustion air pollution control systems, and the ability to process a wide range of solid fuels without modifications. The FB boiler combusts solid fuels in a fluid bed mixture of fuel, char, ash, and other materials (limestone or sand) used to provide the desired bed characteristics. Combustion air forced in at the bottom of the furnace keeps the bed mixture in a constant upward moving fluid flow. Combustion takes place within the furnace at low combustion temperatures ranging from 1,500 to 1,600°F. The low combustion temperature allows for good absorption of SO_2 with alkaline materials (calcium, sodium, etc.) contained in the fuel ash or added with the bed material (i.e., limestone). Additionally, the low combustion temperatures reduce ash fusion problems associated with the combustion of solid fuels in conventional boilers.

There are generally two types of fluidized bed boilers: atmospheric (AFB) and pressurized (PFG). AFB boilers have been used commercially for many years with the circulating bed type being the predominate process type. PFB boilers have very limited commercial scale experience and will not be discussed further.

There are two major AFB boiler types: the "bubbling" bed and the "circulating" bed boiler. The circulating fluidized bed boilers have high fluidized air velocities ranging from 10 to 20 ft/sec, lack a distinct transition from the dense bed at the bottom of the furnace to the dilute zone above, and have a very high flow rate of re-circulated solids. The high fluidizing air velocity results in a turbulent fluidized bed and a high rate of entrained solids carried out of the boiler. These solids are separated from the combustion gases in a cyclone solids disengagement section and returned to the furnace to improve combustion efficiency and limestone utilization. Circulating FB boilers are applicable to biomass although given the high proportion of biomass by weight fraction, with its low sulfur content, the recirculation feature is not essential.

In the bubbling fluidized bed boiler, the bed of materials including the limestone/sand, fuel, and ash is suspended by the combustion air blowing upward through an air distributor plate at relatively low velocities of 1 – 5 ft/sec. The bed itself is typically about four feet deep in its fluidized condition, and is characterized by a sharp density profile at the top of the bed. The sharp drop-off in density indicates the end of the bubbling fluidized bed. In a bubbling bed, the bed level is easy to see, and there is a distinct transition between the bed and the space above. Because most or all of the fuel input is biomass, a bubbling type FB boiler is applicable.

When the boiler is fired on biomass and either coal, pet coke or TDF, SO_2 emissions are controlled directly in the boiler by injecting limestone with fuel directly into the fluidized bed. When the boiler is fired only on biomass, sand will be used instead of limestone because there will be no effective reduction in already low SO_2 emissions that will result from the combustion of biomass. Within the furnace, limestone is first "calcined" to calcium oxide. Calcium oxide then reacts with SO_2 in the fluidized bed to form calcium sulfate. The chemistry of the SO_2 reaction includes the following:

1. Calcination: $CaCO_3$ (s) + 766Btu/(lb of $CaCO_3$) ==> CaO (s) + CO_2 (g)
2. Adsorption: SO_2 (g) + 1/2O_2 (g) + CaO (s) ==> $CaSO_4$ (s) + 6733 Btu/(lb of S)
3. Overall: $CaCO_3$ (s) + SO_2 (g) + 1/2O_2 ==> $CaSO_4$ (s) + CO_2 (g) + 5967 Btu/(lb of S)

Calcium sulfate or gypsum is chemically stable in the fluidized bed at normal operating temperatures and is rejected from the system in the furnace bottom ash draw and in fabric filter baghouse ash draw. The ash draw contains primarily fuel ash, gypsum, unreacted calcium oxide, and char and is disposed of as non-hazardous solid waste.

The primary factor affecting fluidized bed boiler performance is the calcium-to-sulfur molar feed (Ca/S) ratio, which is a function of the fuel sulfur content and the percent SO_2 removal desired. As the calcium content of the bed increases, greater amounts of SO_2 are removed. The importance of the Ca/S ratio extends beyond SO_2 removal; it also affects the mass rate of the bed material flowing through the boiler which affects the size of the boiler, and the operating costs for limestone, furnace wall erosion, and auxiliary power requirements. As the Ca/S ratio increases, the mass of solids flowing through the unit increases.

Dry Flue Gas Desulfurization. The use of a dry flue gas desulfurization system such as lime spray drying followed by a baghouse has the potential to reduce SO_2 emissions by 75 to 90 percent. Using 90 percent control efficiency during the 85 percent biomass and 15 percent coal firing scenario, results in an emission rate of 0.10 lb/MMBtu which represents an overall SO_2 control efficiency of 93 percent. The lowest permitted SO_2 emission rate for a coal-fired FB boiler in the RBLC using lime spray scrubbing technology is 0.22 lb/MMBtu. The lowest permitted SO_2 emission rate for a biomass-fired boiler using lime spray scrubbing technology in the RBLC database is 0.10 lb/MMBtu.

Circulating Dry Scrubber (CDS). The CDS is a once-through dry technology. In a CDS, flue gas, ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the adsorption reactions between lime and SO_2. The by-products leave the absorber in a dry form with the flue gas and are subsequently captured in a downstream particulate collection device. CDS have only been domestically applied to two coal-fired boilers. These boilers are 60 and 80 MW units. Therefore, this technology is considered technically infeasible and will not be considered further in this application.

Duct Sorbent Injection (DSI). DSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb SO_2. In the DSI technology, the reagent is injected into the ductwork between the air heater and particulate control device. The DSI technology is still undergoing significant research and development aimed at improving performance and increasing the scale of applications. Therefore, this technology is considered technically infeasible and will not be considered further in this application.

Activated Carbon Bed. The only potentially applicable regenerable dry technology is based on the use of activated carbon. In the FGD process, the activated carbon is present in a moving bed through which the flue gas flows. The activated carbon serves as the sorbent for removal of the SO_2. As the activated carbon becomes saturated with SO_2, it is regenerated and the SO_2 is released as a stream of gaseous SO_2. There is no record of commercial application of this technology. Therefore, this technology is considered technically infeasible and will not be considered further in this application.

Wet Scrubber. The wet scrubber is a once-through wet technology. In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport/disposal.

The wet scrubber can be further classified on the basis of the reagents used and by-products generated. The typical reagents are lime and limestone. Additives, such as magnesium, may be added to the lime or limestone to increase the reactivity of the reagent. Seawater has also been used as a reagent since it has a high concentration of dissolved limestone. The reaction by-products are calcium sulfite and calcium sulfate. The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced depending on the desired by-product. The most common wet scrubber application utilizes limestone as the reagent and forced oxidation of the reaction by-products to form calcium sulfate.

Wet scrubbers have been applied on coal-fired boilers and are commercially available from a number of suppliers. Wet scrubbers that use limestone, lime, magnesium-enhanced lime, forced oxidation, and inhibited oxidation are all considered technically feasible control technologies with control efficiency of 90 percent to greater than 95 percent.

Regenerable Wet Scrubber. The regenerable wet scrubber is a technology that uses sodium sulfite, magnesium oxide, sodium carbonate, amine, or ammonia as the sorbent for removal of SO_2 from the flue gas. The spent sorbent is regenerated to produce concentrated streams of SO_2 or other sulfur compounds which may be further processed to produce other products. These FGD technologies may require additional flue gas treatment prior to the SO_2 absorption process in order to remove other flue gas constituents such as hydrogen chloride and hydrogen fluoride that may affect the sorbent an/or final by-product.

The sodium sulfite and ammonia based technologies have been commercially applied and are available from a number of suppliers. These technologies are considered to technically feasible with control efficiency of 90 percent to greater than 95 percent. The other technologies either have limited or no record of commercial application; are considered technically infeasible, and will not be considered further in this application.

Two of the add-on controls described in Section 5.3.1 also controls SO_2. These add-on controls are Electro-Catalytic Oxidation and Pahlman Process.

Control Technology Ranking

The primary fuel for the project is biomass which has an extremely low sulfur content of approximately 0.02 percent. Therefore, the use of low sulfur fuel (biomass) is considered technically feasible. Coal cleaning will separate rock and non-combustible material from coal. As a result, the amount ash and SO_2 emitted during coal firing will be reduced. Coal cleaning is considered technically feasible.

A wet scrubber consumes a significant amount of electric energy during operation. Electric motor driven equipment such as slurry feed pumps, recirculating pumps, waste dewatering pumps, reagent preparation equipment, and fans are required to operate wet scrubber systems. The cost of energy was included as an operating cost in the analysis. Wet scrubbers rely on the reaction of calcium in the reagent to remove SO_2 from the flue gas. An inhibited oxidation system will produce calcium sulfite that is more difficult to dewater and has very little potential for commercial use and is typically disposed of in a landfill. A forced oxidation system produces calcium sulfate (synthetic gypsum) which may be marketable depending on its quality and local market conditions.

The wet scrubber system's absorbers are located downstream of the particulate control device. As a result, the wet scrubber system will be a source of fine particulate emissions such as condensibles and aerosols as a result of carryover from the absorbers' mist eliminators. Additionally, a wet scrubber system consumes substantially more water than does a dry scrubber system. The water is used to saturate the flue gas and wash the by-product, and is lost with the moist by-product. In 1993, the Wyoming Department of Environmental Quality reported an additional 20 to 30 percent water usage for a wet scrubber over that of a dry scrubber for the Neil Simpson II unit. A wet scrubber system is technically feasible.

In general, the energy, environmental, and economic impacts discussed for the wet scrubber are applicable to the regenerable wet scrubber. Regenerable wet scrubber systems typically have higher energy consumption than once-through wet scrubber systems due to energy required to regenerate the sorbent and to process the by-product. Ammonia-based regenerable wet scrubber technology requires a large volume of ammonia be stored at the facility. Ammonia is regulated under the EPA Risk Management Program and Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). The capital cost of a regenerable wet scrubber system is higher that the capital cost of a once-through wet scrubber system. The overall economics of the regenerable wet scrubber is strongly dependent on the ability to sell the by-product in order to offset the higher capital and operating costs. These factors typically limit the potential application of regenerable wet scrubbers to applications where high-sulfur fuels are used that result in higher by-product generation rates. The regenerable wet scrubber has a control efficiency that is no better than the control of a once-through wet scrubber and without a market for the sale of the by-product it is more costly. For these reasons, the regenerable wet scrubber will not be considered further in this application.

The total energy consumed by a dry scrubber system will be approximately 50 percent of the energy required to operate a wet scrubber system. The energy is used to operate equipment such as slurry pumps, lime slackers, and material handling systems. A dry scrubber system collects the by-product material and fly ash in a common particulate collection device. This co-mingling of by-product and fly ash makes the commercial value of collected particulate limited. This waste material is typically disposed of in a landfill. Because of the location of the particulate control device in a wet scrubber system (upstream), the dry scrubber system can better control emissions of fine particulate. The particulate control device in the dry scrubber system is located just prior to the stack outlet.

Additionally, the dry scrubber system will provided better control of non-soluble hazardous air pollutants (HAPs). The control of the HAPs is achieved by adsorption onto the fly ash and dry scrubber product filter cake present on the fabric filters in the downstream baghouse. This process also improves the removal of sulfuric acid mist. A dry scrubber system is technically feasible.

A summary of the capital costs and annual O&M costs associated with wet scrubber and dry scrubber and control systems is provided in Table 6-3. The baseline is the FB boiler, with limestone injection. Detailed cost estimates are provided in Appendix C.

TABLE 6-3
FB Boiler SO_2 Control Technology Cost Effectiveness Evaluation
Yellow Pine Energy
Clay County, Georgia

Control Technology	Total Installed Capital Costs	Total Annualized Costs	Annual Emission Reduction[a]	Cost Effectiveness[b]
Wet Scrubber	$38,882,352	$9,954,086	367	$27,123
Dry Scrubber	$12,464,833	$5,037,073	5,382	$936
FB Boiler, with Limestone Injection	Base	Base		

TABLE 6-3
FB Boiler SO_2 Control Technology Cost Effectiveness Evaluation
Yellow Pine Energy
Clay County, Georgia

Control Technology	Total Installed Capital Costs	Total Annualized Costs	Annual Emission Reduction[a]	Cost Effectiveness[b]

[a] Tons/Year emissions based on 1529 MMBtu/hr boiler heat input, 8,760 hours of operation per year, combustion of 85% biomass and 15% coal.
[b] $ per ton of pollutant removed.

Based on information available from vendors, a wet scrubber system will increase the cost of the boiler by approximately $38,882,352. Total annualized costs associated with the wet scrubber system, maintenance labor and materials, lime reagent, waste disposal, makeup water, auxiliary, capital recovery, and indirect operating costs are estimated to be approximately $9,954,086/year. Based on an annual reduction in SO_2 emissions of 367 tpy (670 tpy – 303 tpy) compared to the dry scrubber alternative, the incremental cost effectiveness of the wet scrubber system would be approximately $27,123/ton. This cost is disproportionately high compared to the average cost effectiveness for SO_2 control from a FB boiler, and should preclude a wet scrubber system as BACT for SO_2 control.

Based on information available from vendors, a dry scrubber system will increase the cost of the boiler by approximately $12,464,833. Total annualized costs associated with the dry scrubber system, maintenance labor and materials, lime reagent, waste disposal, makeup water, auxiliary, capital recovery, and indirect operating costs are estimated to be approximately $5,037,073/year. Based on an annual reduction in SO_2 emissions of 5,382 tpy (6,052 tpy – 670 tpy) compared to the baseline alternative, the incremental cost effectiveness of the dry scrubber system would be approximately $936/ton. Based on the relatively small increase in annualized cost, Yellow Pine Energy feels it is appropriate to construct the boiler with a dry scrubber system. Yellow Pine Energy requests the following SO_2 permit limits:

- 3 hour – 0.19 lb/MMBtu
- 24 hour – 0.13 lb/MMBtu
- 30 day – 0.10 lb/MMBtu

6.3.4 Carbon Monoxide (CO)

Combustion is a thermal oxidation process in which carbon, hydrogen, and sulfur contained in a fuel combine with oxygen in the combustion zone to form CO_2, H_2O, and SO_2. CO is generated during the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel. High levels of CO emissions result primarily from poor burner design or sub-optimal firing conditions.

The RBLC database was reviewed to identify technologies used to control CO emissions from fluidized bed boilers. Data from the RBLC for FB boilers indicates that combustion controls are used to control CO emissions (see Appendix B, Table B-4). A broader review of the RBLC database yielded the same results for biomass-fired boilers (see Appendix B, Table B-10). The following is a discussion of the potential control technologies and a discussion of their technical feasibility.

Combustion Controls. Optimization of the design, operation, and maintenance of high combustion temperatures for control of CO emissions will lead to an increase of NO_X emissions. Consequently, typical practice is to design the furnace/combustion system (specifically, the air/fuel mixture and furnace temperature) such that CO emissions are reduced as much as possible without causing NO_X levels to significantly increase. Proper operation and maintenance of the furnace/combustion system will help to minimize the formation and emission of CO by ensuring that the furnace/combustion system operates as designed. This includes maintaining the air/fuel ratio at the specified design point, having proper air and fuel conditions at the burner, and maintaining the fans and dampers in the proper working conditions.

Flares. Flares are commonly used in the control of waste streams from refineries and other chemical processes with low heating value, organic, and gaseous. In the case of a biomass, coal, pet coke, TDF-fired boilers, there are insufficient organics in the exhaust to support combustion without a significant addition of supplementary fuel (natural gas). As a result, the secondary impact of the flare would be the creation of additional emissions, including NO_X.

Afterburning. Afterburners convert CO into CO_2 by utilizing simple gas burners to bring the temperature of the exhaust stream up to 1400°F to promote complete combustion. Afterburners, like flares, would require significant amounts of natural gas and would result in the formation of additional pollutants such as NO_X.

Catalytic Oxidation. A catalytic oxidizer converts the CO in the combustion gases to CO_2 at temperatures ranging from 500°F to 700°F in the presence of a catalyst. A major operating drawback of the catalytic oxidizer is that fine particulate suspended in the exhaust gases can foul and poison the catalyst. The problem of catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device. However, this would require reheating the exhaust gases to the required operating temperature for the catalytic process. Another significant disadvantage of the catalytic oxidizer is that SO_2 in the flue gas stream may be oxidized to form SO_3. The resulting SO_3 may react with moisture in the flue gas to form sulfuric acid.

External Thermal Oxidation (ETO). ETO promotes thermal oxidation of the CO in the flue gas stream in a location external to the boiler. ETO requires heat (1400°F to 1600°F) and oxygen to convert CO in the flue gas to CO_2. There are two general types of ETO that are used for control of CO emissions: regenerative thermal oxidation and recuperative thermal oxidation. The primary difference between regenerative thermal oxidation and recuperative ETO is that regenerative ETO utilized a combustion chamber and ceramic heat exchange canisters that are an integral unit, while recuperative ETO utilizes a separate counterflow heat exchanger to preheat incoming air prior to entering the combustion chamber.

Control Technology Ranking

Combustion controls, which include furnace and combustion system design and proper boiler operation and maintenance, are proven technologies for the reduction of CO emissions. These technologies have been widely demonstrated in similar applications to generate significant lower levels of CO emissions when compared to boilers designed, operated and maintained without regard to CO emissions. Combustion controls are considered technically feasible.

Flares are commonly used in the control of waste streams from refineries and other chemical processes with lower heating value, organic, and gaseous. Flares have not been demonstrated for control of CO from fluidized bed boilers and limitations on the scalability of this technology preclude its commercial availability. In addition, flares are not listed as a control for CO emissions from fluidized bed boilers in the RBLC database. Therefore, flares are considered technically infeasible and will not be considered further in this application.

Afterburners have not been demonstrated for control of CO emissions from fluidized bed boilers. There would be significant secondary impacts and practical considerations to the application of this technology for the reduction of CO emissions from fluidized bed boilers including additional production of NO_X and substantial natural gas usage for a relative small decrease of CO emissions. In addition, afterburners are not listed as a control for CO emissions from fluidized bed boilers in the RBLC database. Therefore, afterburners are considered technically infeasible and will not be considered further in this application.

Catalytic oxidation is generally utilized for CO emission reductions on non-combustion CO sources. Catalytic oxidation has not been demonstrated and is not commercially available for use on fluidized bed boilers. In addition, catalytic oxidation is not listed as a control for CO emissions from fluidized bed boilers in the RBLC database. Therefore, catalytic oxidation is considered technically infeasible and will not be considered further in this application.

ETO is generally utilized for CO emissions reductions on non-combustion sources. Regenerative ETO and recuperative ETO have not been demonstrated and are not commercially available for use on fluidized bed boilers. There significant secondary impacts and other issues that would preclude the use of this technology as a CO emissions reduction technology for fluidized bed boilers. These include additional production of NO_X, substantial natural gas usage for a relatively small decrease of CO emissions and increased maintenance concerns. In addition, ETO is not listed as a control for CO emissions from fluidized bed boilers in the RBLC database. Therefore, ETO is considered technically infeasible and will not be considered further in this application.

Combustion controls are the most effective CO emissions control technology. There are no energy, environmental, or economic impacts that would preclude the use of combustion controls. There are numerous examples of biomass projects where combustion control has been permitted as BACT with emission rates in the range of 0.28 – 0.63 lb/MMBtu. BACT for CO emissions control is the application of combustion controls with an emission limit of 0.30 lb/MMBtu.

6.3.5 Volatile Organic Compounds

Combustion is a thermal oxidation process in which carbon, hydrogen, and sulfur contained in a fuel combine with oxygen in the combustion zone to form CO_2, H_2O, and SO_2. VOC emissions are generated during the combustion process as the result of incomplete thermal oxidation of the hydrocarbons contained in the fuel. High levels of VOC emissions result primarily from poor burner design or sub-optimal firing conditions.

Combustion Controls. As described in Section 5.3.4 for control of CO emissions, combustion controls are also applicable for the control of VOC emissions.

The add-on controls described in Section 5.3.4 for control of CO emissions are also applicable for control of VOC emissions. These add-on controls include flares, afterburning, catalytic oxidation, and external thermal oxidation.

Control Technology Ranking

The potentially applicable technologies for control of VOC emissions identified above were each evaluated for technical feasibility. Generally, technologies that are not commercially available, lack experience in comparable applications, or are not applicable were considered infeasible. The discussion presented in Section 5.3.4 with respect to CO emissions is applicable to VOC emissions and is not repeated here. Therefore, combustion controls is the only technically feasible control technology for VOC emissions. This finding is supported by the RBLC database, which lists combustion controls as the only BACT control strategy for fluidized bed boilers.

In determining the VOC emissions level that can be achieved, unwanted environmental impacts must also considered. As previously discussed with respect to CO control, one consequence of operating the combustion control system to achieve extremely low VOC emission levels is an increase in NO_X emissions. Therefore, the impact of lower VOC emissions must be balanced with higher NO_X emissions. There are numerous examples of biomass and coal projects where combustion control has been permitted as BACT with emission rates in the range of 0.016 – 0.50 lb/MMBtu and 0.003 – 0.05 lb/MMBtu, respectively. BACT for VOC emissions control is the application of combustion controls with an emission limit of 0.020 lb/MMBtu during 100 percent biomass firing and 0.018 lb/MMBtu when biomass is fired with up to 15 percent coal, pet coke, or TDF.

6.3.6 Lead (Pb)

Lead is a heavy metal pollutant found in biomass, coal, pet coke, and TDF. The lead is vaporized during the combustion process and later condensed or absorbed by fly ash suspended in the flue gas. The lead is usually concentrated in the particulate matter with a size less than 10 microns. The control technologies available for control of lead emissions are the same technologies available for control of particulate matter.

Fuel Selection. Lead exists in trace amounts in fuel. The amount of lead varies within and between various types of fuels. In theory, lead emissions can be reduced by burning a fuel that has a lower lead content. In practice, however, fuel is selected on the basis of more significant parameters, such as sulfur content and heating value, and in consideration of the logistics of fuel delivery and the economic impacts of the selection.

Coal Cleaning. Coal cleaning was discussed in detail in Section 5.3.3. Lead may be included in the ash matter of the coal. The relative amounts of lead and other contaminants, the manner in which they are included in the coal assemblage, and the degree to which they can be removed vary widely with different coals.

The add-on controls described in Section 5.3.2 for control of PM-10 emissions also control lead emissions. These add-on controls include fabric filter baghouse, electrostatic precipitator, wet electrostatic precipitator, wet scrubber, venturi scrubber, centrifugal separator (cyclone), and Elcectro-Catalytic Oxidation (ECO).

Control Technology Ranking

The potentially applicable technologies for the control of lead emissions identified above were each evaluated for technical feasibility. Generally, technologies that are not commercially available, lack experience in comparable applications, or are not applicable were considered infeasible. The technically feasible control technologies identified for the control lead emissions are coal cleaning, fabric filter baghouse, electrostatic precipitator, wet electrostatic precipitator, wet scrubber, venturi scrubber, and centrifugal separator (cyclone).

The lead removal efficiency of wet scrubbers, mechanical collectors, and ESPs would be less than the removal efficiency of fabric filtration for FB boilers using limestone injection. Additionally, these other control technologies offer no measurable benefit in increased lead control if placed upstream or downstream of a properly sized baghouse. As such, a fabric filter is the top performing control technology. The proposed BACT control of the FB boiler lead emissions is a fabric filter baghouse with an emission limit of 1.8×10^{-5} lb/MMBtu.

6.3.7 Mercury (Hg)

Mercury emissions are emitted as a result of trace levels of this element in the fuel (biomass, coal, Pet Coke, and TDF) combusted in the FB boiler. During combustion, mercury is volatilized and may be emitted as either inorganic oxides (particulate) or elemental form. Georgia Rules for Air Quality Control (Chapter 391-3-1) establish rules for mercury emissions for new electric generating units. Specifically, this rule requires affected units to meet the requirements for BACT.

As previously discussed, Yellow Pine Energy is proposing add-on controls for PM-10 and SO_2. These controls (fabric filter baghouse and dry scrubber system) are also effective in controlling mercury emissions. Activated carbon injection is also effective in controlling mercury emissions.

Technically feasible technologies identified for the control of mercury emissions are fabric filter baghouses, dry scrubbers, and activated carbon injection.

Rank Remaining Control Technologies

The fabric filter baghouse and dry scrubber system combination is expected to have an overall 90% removal efficiency for mercury. The addition of an activated carbon injection system would potentially increase the overall mercury removal from 90% to 98%.

Economic Evaluation

The potential energy, environmental and economic impacts associated with fabric filter baghouses and dry scrubbers were previously discussed and are not repeated here. With annual mercury emissions of 0.0023 tons per year (100% Biomass firing) from the FB boiler and conservatively assuming a high BACT economic threshold of $10,000/ton, the annualized cost for a pollution control device would have to be less than $23 at 100% efficiency before the economics would not preclude it from selection. The activated carbon injection technology has annualized costs in the range of $2,000,000 therefore it is precluded from use for economic reasons.

Proposed BACT

Based on the preceding analysis, the activated carbon injection technology is rejected as BACT because of severe economic impacts. Therefore, BACT for mercury emission control is fabric filter baghouse and dry scrubber system combination. Yellow Pine Energy proposes to limit mercury emissions based on an overall 90% removal efficiency of mercury by the fabric filter baghouse and dry scrubber system combination. The uncontrolled and controlled emission rates by fuel are shown in Table 6-4.

TABLE 6-4
FB Boiler Mercury Emission Rates by Fuel
Yellow Pine Energy
Clay County, Georgia

Fuel	**Uncontrolled**	**Controlled**
100% Biomass	4.87E-05 lb/MWhr 3.5E-06 lb/MMBtu	4.87E-06 lb/MWhr 3.5E-07 lb/MMBtu
85% Biomass/15% Coal	4.96E-05 lb/MWhr 3.57E-06 lb/MMBtu	4.96E-06 lb/MWhr 3.57E-07 lb/MMBtu
85% Biomass/15% Pet Coke	5.06E-05 lb/MWhr 9.62E-06 lb/MMBtu	5.06E-06 lb/MWhr 9.62E-07 lb/MMBtu
85% Biomass/15% TDF Firing	4.28E-05 lb/MWhr 3.08E-06 lb/MMBtu	4.28E-06 lb/MWhr 3.08E-07 lb/MMBtu

These limits are based on 12-month averages. Based on 100% biomass firing, annual emissions are expected to be 4.69 lb/yr. Yellow Pine Energy proposes to demonstrate compliance with these limits by conducting source emission tests. Note the proposed mercury emissions are a factor of ten less than the emission rate in the recently vacated

National Emissions Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters (3.0E-06 lb/MMBtu for new large solid fuel units) which is commonly referred to as the Boiler MACT.

6.4 Auxiliary Boiler

As discussed previously, the proposed Facility will install and operate a fuel oil-fired auxiliary boiler with a heat input rating of 25 MMBtu/hr (oil-fired). The auxiliary boiler will operate a maximum of 250 hours per year. Aside from maintenance testing of the auxiliary boiler, it will only be used during facility startup activities.

6.4.1 Nitrogen Oxides

The RBLC database was reviewed to identify technologies used to control NO_X emissions from fuel oil-fired boilers similar in size to the boiler proposed for this project. Data from the RBLC for fuel oil-fired boilers indicates that low NO_X burners and flue gas recirculation are used to control NO_X emissions from auxiliary boilers (see Appendix D, Tables D-1). The following is a discussion of the potential control technologies and a discussion of their technical feasibility.

Potential NO_X control technology options were determined to be fuel selection, water/steam injection, low excess air, low NO_X burners, overfire air, natural gas reburning, fuel lean gas reburning, advanced gas reburning, amine enhanced gas injection, flue gas recirculation, selective catalytic reduction, selective non-catalytic reduction, $SCONO_X$, electro-catalytic oxidation, and Pahlman process.

Due to the physical configuration and small size of the auxiliary boiler, water/steam injection, overfire air, natural gas reburning, lean gas reburning, advanced gas reburning, amine enhanced gas injection, and selective non-catalytic reduction are deemed technically infeasible. $SCONO_X$, electro-catalytic oxidation, and Pahlman process are not commercially available therefore, they are also deemed infeasible.

In summary, the technically feasible technologies identified for the control of NO_X emissions from the auxiliary boiler are low excess air, low NO_X Burners (LNB), flue gas recirculation

(FGR), and selective catalytic reduction (SCR).

Rank Remaining Control Technologies

A review of the technical literature and the RBLC database indicated that LNB's are the most common applied technology for the control of NO_X emissions from oil-fired auxiliary boilers.

NO_X emission rate of 0.14 lb/MMBtu was developed from an AP-42 emission factor for boilers with a heat input rating of less than 100 MMBtu/hr and can be expected for a distillate oil-fired auxiliary boiler equipped with LNB's. This emission level can be affected by factors such as boiler size, boiler operating load, fuel characteristics, and secondary impacts from other pollutant control technologies. Table 6-5 lists, in order of decreasing effectiveness each of the NO_X control, technologies deemed technically feasible along with control efficiency.

TABLE 6-5
Control Efficiencies for NO_X Technologies – Auxiliary Boiler
Yellow Pine Energy
Clay County, Georgia

Control Technology	Efficiency
SCR + FGR + LNB	70% to 90%
FGR + LNB	50% to 80%
LNB	30% to 50%
Low Excess Air	0 to 15%

Because LNB's have become a standard component of boiler design, the emissions associated with LNB's are considered to be the baseline.

Economic Evaluation

The potential energy, environmental and economic impacts of the feasible control technologies were considered and are discussed below starting with the most effective.

The environmental and energy impacts associated with SCR technology were described in Section 5.3.1 and are not repeated here. The SCR will require substantial initial capital investment and significant annual costs for the operation and maintenance system. Based on the size and limited operation of the auxiliary boiler, these costs preclude the use of SCR.

There are no environmental impacts associated with the application of FGR. FGR will require additional energy for recirculating the flue gas and will require additional costs; however, the energy and economic impacts are not significant enough to preclude the use of FGR. One environmental impact associated with the use of LNB's is an increase in the amount of CO and VOC emissions. There are no significant energy or economic impacts. Overall, none of the impacts preclude the use of LNB technology.

Proposed BACT

Based on the analysis presented above, the application of the most effective control technology, SCR in combination with LNB and FGR, is rejected because of severe economic impacts. Therefore, BACT for NO_X emission control is the application of LNB and FGR with an emission limit of 0.14 lb/MMBtu.

6.4.2 PM-10

PM-10 emissions are emitted from oil-fired boilers as a result of the ash contained in the oil. Ash is the inorganic matter that does not participate in the combustion reaction. The only potentially applicable lower emitting process/practice is the use of low ash oil. Combustion of a fuel oil containing less ash will result in less ash generation, hence, less PM-10 emissions.

The add-on controls described for the FB boiler in Section 5.3.2 for control of PM-10 emissions are also applicable for the auxiliary boiler. These add-on controls include fabric filter baghouses, electrostatic precipitator (ESP), wet electrostatic precipitator, wet scrubber, venture scrubber, centrifugal separator (cyclone), and electro-catalytic oxidation.

The potentially applicable technologies for the control of PM-10 emissions identified above were each evaluated for technical feasibility. Electro-catalytic oxidation is deemed technically infeasible because it is not commercially available nor has it been applied in a similar installation.

In summary, the technically feasible technologies identified for control of PM-10 emissions are fabric filter baghouses, electrostatic precipitator (ESP), wet electrostatic precipitator, wet scrubber, venture scrubber, centrifugal separator (cyclone).

Rank Remaining Control Technologies

Summaries of the most stringent PM-10 limits for oil-fired auxiliary boilers found in the RBLC database are shown in Appendix D, Table D-2. Use of low ash fuels and good combustion practices are the only control technologies identified for control of PM-10 emissions from small oil-fired boilers. All of the limits listed are assumed to only apply to the filterable portion because, until very recently, this has been the industry standard practice.

Table 6-6 lists in order of decreasing effectiveness each of the boiler PM-10 control technologies deemed technically feasible along with the control efficiency and emission level for the Facility.

TABLE 6-6
Control Efficiencies for PM-10 Technologies – Auxiliary Boiler
Yellow Pine Energy
Clay County, Georgia

Control Technology	Filterable Control Efficiency	Filterable Emission Rate (lb/MMBtu)
Fabric Filter Baghouse	99.5%	8.5×10^{-5}
Wet Electrostatic Precipitator	99%	1.7×10^{-4}
Electrostatic Precipitator	99%	1.7×10^{-4}
Venturi Scrubber	95%	8.5×10^{-4}
Wet Scrubber	95%	8.5×10^{-4}
Centrifugal Separator	95%	8.5×10^{-4}
Low Ash Fuel Oil	Baseline	0.017

Economic Evaluation

The potential energy, environmental and economic impacts associated with fabric filter baghouses, WESPs, ESPs, venturi scrubbers, wet scrubbers, and centrifugal separators were discussed in Section 5.3.2 and are not repeated here. With annual emissions of 0.054 tons per year from the auxiliary boiler and conservatively assuming a high BACT economic threshold of $10,000/ton, the annualized cost for a pollution control device would have to be less than $540 at 100% efficiency before the economics would not preclude it from selection. Each of these technologies have annualized costs far in excess of this value, therefore they are precluded from use for economic reasons.

Proposed BACT

Based on the preceding analysis, the application of add-on control technology is rejected as BACT because of severe economic impacts. Therefore, BACT for PM-10 emission control is the use of low ash fuel oil with an emission limit of 0.017 lb/MMBtu. This emission rate was developed from an AP-42 emission factor for boilers with a heat input rating of less than 100 MMBtu/hr.

6.4.3 Sulfur Dioxide

The RBLC database was reviewed to identify technologies used to control SO_2 emissions from fuel oil-fired boilers. Data from the RBLC for fuel oil-fired boilers indicates that good combustion practices and low sulfur content fuel are used to control SO_2 emissions from auxiliary boilers (see Appendix D, Tables D-3). The following is a discussion of the potential control technologies and a discussion of their technical feasibility.

Lower emitting processes/practices for the control of SO_2 emissions are pre-combustion technologies that have the potential to result in lower levels of SO_2 emissions. Lower emitting processes/practices include firing lower sulfur fuel oil. Add-on controls for SO_2 reduction are post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. The technologies are often referred to as flue gas desulfurization (FGD) systems. The add-on controls described in Section 5.3.3 for control of SO_2 emissions are also applicable for the auxiliary boiler. These add-on controls include wet scrubbers, dry scrubbers, circulating dry scrubbers (CDS), duct sorbent injection (DSI), furnace sorbent injection (FSI), limestone injection dry scrubbing (LIDS), activated carbon bed, electro-catalytic oxidation (ECO), and Pahlman Process.

The potential applicable technologies for the control of SO_2 emissions identified above were each evaluated for technical feasibility. Due to the physical configuration and small size of the auxiliary boiler, add-on technologies that require injection of sorbent into the furnace are deemed to be technically infeasible. Circulating dry scrubbers, activated carbon bed, electro-catalytic oxidation and the Pahlman Process are deemed technically infeasible due to their lack of commercial availability. In summary, the technically feasible technologies identified for the control of SO_2 emissions are low sulfur fuel, wet scrubbers, and dry scrubbers.

Rank Remaining Control Technologies

In general, wet scrubbers are more effective than dry scrubbers; however, in applications where the SO_2 content in the incoming flue gas is very low (such as oil-fired boilers), neither scrubber can achieve the control efficiencies that are possible in high SO_2 applications.

Summaries of the most stringent SO_2 limits for oil-fired auxiliary boilers found in the RBLC are shown in Appendix D, Table D-3. Use of low sulfur fuels and good combustion practices are the only control technologies identified for control of SO_2 emissions from small oil-fired boilers.

Economic Evaluation

The potential energy, environmental and economic impacts associated with wet and dry scrubbers were discussed in Section 5.3.3. The energy and environmental impact discussions are equally applicable to the oil-fired auxiliary boiler and are not repeated here. With annual emissions of 0.16 tons per year from the auxiliary boiler and conservatively assuming a high BACT economic threshold of $10,000/ton, the annualized cost for a pollution control device would have to be less than $1,600 at 100% efficiency before the economics would not preclude it from selection. With annualized costs in excess of this value for both types of scrubbers, they are precluded from use for economic reasons.

Proposed BACT

Based on the preceding analysis, the application of a wet or dry scrubber is rejected as BACT because of severe economic impacts. Therefore, BACT for SO_2 emission control is the use of low sulfur fuel oil and good combustion practices with an emission limit of 0.051 lb/MMBtu. This emission rate was developed from an AP-42 emission factor for boilers with a heat input rating of less than 100 MMBtu/hr and No. 2 fuel oil with a sulfur content of 0.050 percent.

6.4.4 Carbon Monoxide

The lower emitting processes/practices described for the FB boiler in Section 5.3.4 for control of CO emissions are also applicable for the auxiliary boiler. These lower emitting processes/practices include combustion controls. The add-on controls described for the FB boiler in Section 5.3.4 for control of CO emissions are also applicable for the auxiliary boiler. These add-on controls include flares, afterburners, catalytic oxidation, and external thermal oxidation.

The potentially applicable technologies for control of CO emissions identified above were each evaluated for technical feasibility. Combustion controls are deemed technically feasible and all of the add-on controls are deemed technically infeasible for the reasons described in Section 5.3.4.

Rank Remaining Control Technologies

Combustion controls are considered the only technically feasible option for the control of CO emissions. This finding is supported by the RBLC database which list combustion controls as the only BACT control strategy for auxiliary boilers. Summaries of the CO emission limits for distillate oil-fired auxiliary boilers are presented in Appendix D, Table D-4.

Economic Evaluation

Combustion controls are the most effective CO emissions control technology. There are no energy, environmental, or economic impacts that would preclude the use of combustion controls.

Proposed BACT

Based on the analysis presented above, BACT for CO emissions control is the application of combustion controls with an emission limit of 0.036 lb/MMBtu. This emission rate was developed from an AP-42 emission factor for boilers with a heat input rating of less than 100 MMBtu/hr.

6.4.5 Volatile Organic Compounds (VOC)

The lower emitting processes/practices described for the control of CO emissions from the FB boiler in Section 5.3.4 are also applicable for control of VOC emissions from the auxiliary boiler. These lower emitting processes/practices include combustion controls. The add-on controls described for the FB boiler in Section 5.3.4 for control of CO emissions are also applicable for control of VOC emissions from the auxiliary boiler. These add-on controls include flares, afterburners, catalytic oxidation, and external thermal oxidation.

The potentially applicable technologies for control of VOC emissions identified above were each evaluated for technical feasibility. Combustion controls are deemed to technically feasible and all of the add-on controls are deemed technically infeasible for the reasons described in Section 5.3.4.

Rank Remaining Control Technologies

Combustion controls are considered the only technically feasible option for the control of VOC emissions. This finding is supported by the RBLC database which list combustion controls as the only BACT control strategy for auxiliary boilers. Summaries of the VOC emission limits for distillate oil-fired auxiliary boilers are presented in Appendix D, Table D-5.

Economic Evaluation

Combustion controls are the most effective VOC emissions control technology. There are no energy, environmental, or economic impacts that would preclude the use of combustion controls.

Proposed BACT

Based on the analysis presented above, BACT for CO emissions control is the application of combustion controls with an emission limit of 0.0024 lb/MMBtu. This emission rate was developed from an AP-42 emission factor for boilers with a heat input rating of less than 100 MMBtu/hr.

6.5 Material Storage and Handling

6.5.1 Non-Fugitive Emissions

This section contains the BACT analysis for the non-fugitive material (e.g. biomass, coal, pet coke, limestone, sand, and ash) storage and handling systems. Non-fugitive emissions are those which pass through a stack, chimney, vent, or other functionally-equivalent opening. By enclosing material handling and storage operations they are converted from a fugitive source into one that passes through a functionally-equivalent opening. Enclosures are applied where reasonable practical throughout the Facility. The technical feasibility of each of the different types of enclosures is dependent upon a number of factors including the functionality, safety, and practicality of the enclosure for the specific application. For example:

- Transfer point enclosures, usually used in conjunction with other control technologies such as water sprays or fabric filters, are technically feasible for the control of PM/PM-10 emissions at material transfer points where structural and operational considerations do not preclude their use.

- Material storage building and silos are technically feasible for the control of PM/PM-10 emissions from material handling operations but only in applications where structural and operational considerations do not preclude their use.

Enclosed sources at the Facility are:

- Fuel Process Buildings 1 and 2 (FPB1 and FPB2)
- Tripper Deck Day Silos 1 – 5
- Fly Ash Silo

Non-fugitive, non-combustion source particulate matter emissions are created as a result of the breakdown of solid material into fines which have the potential to become airborne. This process is commonly referred to as dusting. Particulate matter emissions that are less than 10 microns in diameter are referred to as PM-10. Non-combustion PM-10 emissions can potentially be generated as a result of the operation of the biomass, coal, pet coke, limestone, sand, and ash handling systems. These material handling operations include emissions from vents at enclosed fuel process buildings and storage silos.

Lower emitting processes and practices for the control of PM/PM-10 emissions are controls that either lower the PM/PM-10 generation rate or trap airborne material prior to release. Examples of lower emitting processes and practices for control of PM/PM-10 emissions include the conditioning of a material prior to transfer. Water and surfactants sprays control the creation of PM/PM-10 emissions by binding the smaller particles to the surface of the material, or by actively suppressing PM/PM-10 emissions through direct contact between spray droplets and PM/PM-10 within the air. Add-on controls prevent the release of PM/PM-10 or remove PM/PM-10 from the air. Fabric filters are an example of the implementation of add-on controls for PM/PM-10 emissions.

The technology identified for the control of PM/PM-10 emissions from material handling operations were evaluated for technical feasibility. The following is a summary of the results of this evaluation for the PM/PM-10 emissions control technologies identified above. Materials conditioning is a technically feasible means of controlling PM/PM-10 emissions during materials handling operations, but only to the extent that the material handling process does not adversely impact the material or the material handling process. Examples of technically infeasible applications of this methodology would include the use of sprays that may cause a chemical reaction, application of water in freezing weather, or excessive wetting of the fuel. Fabric filters are technically feasible PM/PM-10 emissions control technology only when the source of emissions can be enclosed and funneled through a vent.

Rank Remaining Control Technologies

The technically feasible technologies for the control of PM/PM-10 emissions from material handling operations are employed individually and in combination with other technologies to provide the optimum level of control effectiveness for each application. The following summary provides a more application-specific description of the control effectiveness provided by each of the previously identified feasible control technologies. Fabric filters are extremely effective at reducing PM/PM-10 emissions when utilized to treat the vent from enclosed PM/PM-10 emission sources. Depending upon the application, a fabric filter can achieve control efficiencies of greater than 99%. The application of water to biomass, coal, pet coke, limestone, and sand effectively binds the PM/PM-10 to the surface of the material being transferred. When the use of water sprays is not technically feasible, specially designed enclosures can provide control efficiencies between 50% and 90%.

Economic Evaluation

A review of the RBLC database indicate that each of the PM/PM-10 control technologies identified for use at the Facility has been proven effective and established as BACT for PM/PM-10 emissions control in comparable applications at other facilities. Based upon this and a review of all site specific considerations for the proposed PM/PM-10 emissions control technologies, there are no energy or environmental impacts associated with the use of the identified PM/PM-10 control technologies that would preclude their being selected as BACT. However, no one PM/PM-10 emission control technology can be economically applied for control of PM/PM-10 from all emission sources. For example, it would be cost prohibitive, and functionally and operationally restrictive, to use a full enclosure for control of PM/PM-10 emissions from all material storage piles. For this reason, the economic impact of the application of each PM/PM-10 emission control technology on each emission source was considered in establishing BACT.

Proposed BACT

Table 6-7 indicates the selected BACT for each non-fugitive, non-combustion PM/PM-10 emission source within the Facility.

TABLE 6-7
BACT for PM/PM-10 Emissions from Material Handling Operations (Non-Fugitive Emissions)
Yellow Pine Energy
Clay County, Georgia

Emission Unit	BACT
Fuel Process Buildings 1 and 2, Tripper Deck Day Silos 1 – 5	Water Sprays; Enclosure and Fabric Filter with 99% control
Fly Ash Silo	Enclosure and Fabric Filter with 99% control

6.5.2 Fugitive Emissions

This section contains the BACT analysis for the fugitive emissions associated with biomass, coal, pet coke, limestone, sand, and ash storage and handling systems. EPA defines fugitive emissions in the Title V regulations as “those emissions which could not reasonably pass through a stack, chimney, vent, or other functioning equivalent opening”.

Fugitive emission sources at the Facility will include:

- Barge/Clamshell Unloading
- Conveyor Transfer Towers 1 – 3 and 5 - 8
- Biomass, Coal, Pet Coke, Limestone, and Sand Storage Piles
- Fly Ash Trucks
- Plant Roads

Fugitive PM-10 emissions from these sources are generated primarily as a result of the operation of the biomass, coal, pet coke, limestone, sand, and ash handling systems or wind erosion of storage piles. These non-fugitive material handling operations include the transfer (material drop and transfer points), transport (barge, truck, and conveyor), and storage (active and reserve).

Lower emitting processes and practices for the control of PM/PM-10 emissions are controls that lower the PM/PM-10 generation rate. Examples of lower emitting processes and practices for control of PM/PM-10 emissions include the conditioning of a material prior to transport, compacting storage piles, and limiting speeds on plant roads. Add-on controls prevent the release of PM/PM-10 or remove PM/PM-10 from the air. Water and surfactant sprays, surface sealants, and enclosures are examples of the implementation of add-on controls for PM/PM-10 emissions. Water and surfactant sprays control the creation of PM/PM-10 emissions by binding the smaller particles to the surface of the material, or by actively suppressing PM/PM-10 emissions through direct contact between spray droplets and PM/PM-10 within the air. Surface sealants are chemical treatments that create a protective layer on the surface of the material to bind and contain PM/PM-10. Enclosures control PM/PM-10 emissions by isolating the PM/PM-10 source from the environment. Examples of types of enclosures include material transfer chutes, conveyor hooding, and storage pile covers.

The technologies identified for the control of PM/PM-10 emissions from material handling operations were evaluated for technical feasibility. The following is a summary of the results of this evaluation for the PM/PM-10 emissions control technologies identified above.

Material conditioning is a technically feasible means of controlling PM/PM-10 emissions during material handling operations, but only to the extent that the material conditioning does not adversely impact the material on the material handling process. Compaction is a technically feasible method of controlling fugitive PM/PM-10 emissions, but only when applied to large piles of compactable material that are not frequently disturbed. Limiting the speed of vehicles on roadways is a technically feasible way of minimizing the generation of PM/PM-10 form the roadway surface. Water and surfactant sprays are technically feasible for all applications except those where the integrity of the material or process would be compromised by application of the spray. Examples of technically infeasible applications would include the use of sprays that may cause a chemical reaction and application of water in freezing weather.

Surface sealants are technically feasible PM/PM-10 emissions control technology only when applied to the surface of material that will not be frequently disturbed. The technically feasibility of each of the different types of enclosures is dependent upon a number of factors including the functionality, safety, and practicality of the enclosure for the specific application. Examples included:

- Material transfer chutes are a technically feasible technology for the control of PM/PM-10 emissions at material loading
- Conveyor enclosures (hooded conveyors) are technically feasible technology for the control of PM/PM-10 emissions from conveyors
- Enclosure of coal and pet coke storage piles
- Enclosure of fly ash trucks

Rank Remaining Control Technologies

The technically feasible technologies for the control of PM/PM-10 emissions from the material handling operations are employed individually and in combination with other technologies to provide the optimum level of control effectiveness for each application. The following summary provides a more application-specific description of the control effectiveness provided by each of the previously identified feasible control technologies.

Water sprays and enclosures, when employed in combination, are extremely effective at reducing PM/PM-10 emissions from the coal and pet coke storage piles. Since the coal and pet coke storage piles will be sprayed with water and partially enclosed (as described in Section 2), an overall PM/PM-10 control efficiency of 98% is assumed (i.e., 80% for water sprays and 90% for partial enclosure).

Although the biomass storage pile will not be covered, the pile stacker will utilize a telescopic chute and water sprays to minimize PM/PM-10 emissions. Furthermore, incoming chips are expected to be "green" and relatively high in moisture content. As a result, a control efficiency of 99% has been assumed.

Water sprays and surface sealants will be used to control emissions from the uncovered limestone and sand storage piles. The application of water and surface sealants to the limestone and sand storage piles has been assumed to have a 95% control efficiency for PM/PM-10 emissions.

For the fuel, limestone, and sand conveying systems, the use of an enclosure, to minimize the exposed surface area of the material (when combined with water sprays on storage piles) is assumed to result in a PM/PM-10 control efficiency of 100%.

For material handling transfer towers during transfer of fossil fuel, limestone, and sand, the use of an enclosure, to minimize the exposed surface area of the material is assumed to result in a PM/PM-10 control efficiency of 90%. Additionally, incoming chips are expected to be "green" and relatively high in moisture content. As a result, a control efficiency of 99% has been assumed biomass transfer.

For fly ash loading to trucks, the use of an enclosure and baghouse has been assumed to result in a PM/PM-10 control efficiency of 99%.

For fugitive emissions from plant roads, the application of water sprays and regular sweeping practices effectively reduces silt emissions from plant roads. Additionally, limiting vehicle speeds on plant roads will be an enforced practice, to further minimizing PM/PM-10 emissions.

Economic Evaluation

A review of the RBLC database indicated that each of the PM/PM-10 control technologies identified for use at the Facility has been proven effective and established as BACT for PM/PM-10 emissions control in comparable applications at other facilities. Based upon this and a review of all site specific considerations for the proposed PM/PM-10 emissions control technologies, there are no energy or environmental impacts associated with the use of the identified PM/PM-10 control technologies that would preclude their being selected as BACT. However, no one PM/PM-10 emission control technology can be economically applied for control of PM/PM-10 from all emission sources. For example, it would be cost prohibitive, and functionally and operationally restrictive, to use a full enclosure for control of PM/PM-10 emissions from material storage piles. For this reason, the economic impact of the application of each PM/PM-10 emission control technology on each emission source was considered in establishing BACT.

Proposed BACT

Table 6-8 indicates the selected BACT for each of the fugitive and non-fugitive PM/PM-10 emission source discussed above.

TABLE 6-8
BACT for PM/PM-10 Emissions from Material Handling Operations Emission Units – Fugitive Emissions
Yellow Pine Energy
Clay County, Georgia

Emission Unit	BACT
Barge/Clamshell Unloading (Coal, Pet Coke, Limestone, and Sand)	Water Sprays
Transfer Towers	Enclosure
Conveyors	Enclosure and Waters Sprays
Coal and Pet Coke Storage Piles	Enclosure and Waters Sprays
Biomass, Limestone, and Sand Storage Piles	Water Sprays
Storage Pile Load-in (Biomass, Coal, Pet Coke, Limestone, and Sand)	Telescopic chute and water sprays
Fly Ash Truck Loading	Enclosure

6.6 Cooling Tower

This section contains the BACT analysis for the multi-cell mechanical draft cooling towers. Cooling water will circulate through the surface condenser to remove the heat released by the condensing steam and then will flow to the multi-cell mechanical draft cooling tower where heat will be rejected to the environment, primarily through evaporation of a portion of the cooling water. A very small portion of the cooling water may be carried into the ambient air in liquid form. This water is referred to as drift, and can contain a small amount of mineral matter that will be present in the cooling water. The mineral matter is a small source of PM/PM-10 emissions from the Facility.

Drift eliminators are the only control technology identified for limiting PM/PM-10 emissions from cooling towers. Drift eliminators are designed to capture as many of the droplets as possible before the air stream and entrained particulate exits the cooling towers. This is accomplished by imposing a physical obstacle of varied geometry to the exiting air stream path. As the air stream changes direction to weave through the convoluted path imposed by the drift eliminator, inertia force causes the droplet to impinge upon the drift eliminator. Inertia force causes the droplets to impinge upon the drift eliminator surface. Surface tension acts to retain the droplets, after which the force of gravity causes the accumulated droplets to drop back into the cooling tower basin.

Economic Evaluation

Drift eliminators are the most effective control technology to limit PM/PM-10 emissions from cooling towers. From a review of the RBLC database and other sources, the removal effectiveness of drift eliminators very high. The projected efficiency of the drift eliminators is estimated to limit the amount of entrained drift leaving the cooling towers to less than 0.001% of the mass flow rate of water circulating through the cooling tower.

Proposed BACT

Based on the analysis presented above, the use of current technology drift eliminators on the cooling tower represents BACT for the control of cooling tower fugitive PM/PM-10 emissions. The proposed BACT emission limit is equal to the mass flow rate of drift that would correspond to a drift eliminator effectiveness of 0.001%.

6.7 BACT Summary

Table 6-9 presents the control technologies and emission rates being proposed as BACT for the Yellow Pine Energy Facility.

TABLE 6-9
BACT for PM/PM-10 Emissions from Material Handling Operations Emission Units – Fugitive Emissions
Yellow Pine Energy
Clay County, Georgia

Emission Unit	Pollutant	Type of Control	Emission Rate
FB Boiler	NO_X	Low NO_X Burner and SNCR	0.10 lb/MMBtu 153 lb/hr
	PM-10	Fabric Filter Baghouse	0.033lb/MMBtu 50.5 lb/hr
	SO_2	FB Boiler and Dry Scrubber System	3 hour – 0.19 lb/MMBtu 291 lb/hr (85% Biomass/15% Coal) 24 hour – 0.13 lb/MMBtu 30 day – 0.10 lb/MMBtu
	CO	Combustion Controls	0.30 lb/MMBtu 459 lb/hr
	VOC	Combustion Controls	0.020 lb/MMBtu (30.58 lb/hr, 100% Biomass) 0.018 lb/MMBtu (30.1 lb/hr, 85% Biomass/15% Fossil Fuel)
	Lead	Fabric Filter Baghouse	1.8×10^{-5} lb/MMBtu
	Mercury	Dry Scrubber System and Fabric Filter Baghouse	4.87E-06 lb/MWhr (3.5E-07 lb/MMBtu, 100% Biomass Firing) 4.96E-06 lb/MWhr (3.57E-07 lb/MMBtu, 85% Biomass/15% Coal Firing) 5.06E-06 lb/MWhr (9.62E-07 lb/MMBtu, 85% Biomass/15% Pet Coke Firing) 4.28E-06 lb/MWhr (3.08E-07 lb/MMBtu, 85% Biomass/15% TDF Firing)
Auxiliary Boiler	NO_X	FGR and Low NO_X Burners	0.14 lb/MMBtu 3.58 lb/hr
	PM-10	Low Ash Fuel Oil	0.017 lb/MMBtu 0.43 lb/hr
	SO_2	No. 2 Fuel Oil (Sulfur Content of 0.050%)	0.051 lb/MMBtu 1.27 lb/hr
	CO	Combustion Controls	0.036 lb/MMBtu 0.90 lb/hr
	VOC	Combustion Controls	0.0024 lb/MMBtu 0.061 lb/hr

TABLE 6-9
BACT for PM/PM-10 Emissions from Material Handling Operations Emission Units – Fugitive Emissions
Yellow Pine Energy
Clay County, Georgia

Emission Unit	**Pollutant**	**Type of Control**	**Emission Rate**
Fuel Process Building 1	PM-10	Water Sprays; Enclosure and Fabric Filter with 99% control	0.0023 lb/hr
Fuel Process Buildings 2	PM-10	Water Sprays; Enclosure and Fabric Filter with 99% control	0.0035 lb/hr
Tripper Deck Day Silos 1 – 5	PM-10	Water Sprays; Enclosure and Fabric Filter with 99% control	0.0041 lb/hr
Fly Ash Silo	PM-10	Enclosure and Fabric Filter with 99% control	4.4E-07 lb/hr