January 31, 2011 Project No. 10389656

Mr. Al Linero, P.E.
Program Administrator, Special Projects Section
Florida Department of Environmental Protection
Division of Air Resource Management
2600 Blair Stone Road MS 5500
Tallahassee, Florida 32399-2400

RE: AIR CONSTRUCTION PERMIT APPLICATION
NORTHWEST FLORIDA RENEWABLE ENERGY CENTER, LLC (NWFREC)
PORT ST. JOE, FL

Dear Mr. Linero:

The Northwest Florida Renewable Energy Center, LLC (NWFREC), is proposed as a power project in Port St. Joe (the Project), which would use biomass to generate electricity. Specifically, biomass will be gasified, and the product gas that is produced will be combusted in energy-efficient, combined cycle combustion turbines to produce electricity. The proposed project will generate a nominal net 55.4 megawatts (MW) of electricity.

Biomass gasification units such as the ones being proposed by the NWFREC represent an excellent opportunity for the State by providing a reliable, renewable energy source, as well as helping to curb the State's GHG emissions.

This letter serves to transmit NWFREC's minor source air construction permit application for the proposed Port St. Joe project. One original and three copies are enclosed. In addition, enclosed are application forms for an Acid Rain permit, a Certificate of Representation, and a check for $9,750 to cover the permit processing fee. Finally, one of the process schematic diagrams, referenced in the application (Figure 2-6), is being claimed as company confidential and will be transmitted under separate cover.

If you should have any questions regarding the enclosed application package, please don't hesitate to contact either Glenn Farris of Biomass Energy Holdings (BEH), LLC at (770) 662-0256 or me at (813) 287-1717. Thank you in advance for your timely processing of this application.

Sincerely,
GOLDER ASSOCIATES INC.

Scott Osbourn, P.E.
Associate and Tampa Operations Manager

Attachment

cc: Kenn Davis, NWFREC
Glenn Farris, NWFREC
Andrew Grant, NWFREC

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REPORT

AIR CONSTRUCTION PERMIT APPLICATION

Northwest Florida Renewable Energy Center, LLC

Submitted To: Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

On Behalf Of: Biomass Energy Holdings, LLC
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Distribution: 4 Copies—Florida Department of Environmental Protection
2 Copies—Biomass Energy Holdings, LLC
1 Copy—Golder Associates Inc.

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1.0 INTRODUCTION

To improve domestic energy sources and to address global climate change issues, the State of Florida is encouraging the expanded use of biomass-based energy, both for transportation needs and electrical generation. The Governor's Action Team on Energy and Climate Change has recommended that the State expand its biomass-based energy sources, citing several benefits including economic development, energy security, fuel diversity, and reliability as well as helping the State achieve its greenhouse gas (GHG) emissions reduction objectives. Biomass (which is a broad term covering various types of non-fossil organic material, such as agricultural crops and byproducts, landscape and yard trimmings, logging and lumber mill residues, untreated wood materials, etc.) is relatively abundant in Florida as well as the southeastern U.S., and is a proven, reliable source of renewable energy which can be considered carbon-neutral.

Biomass can be combusted in a traditional boiler to produce electricity, or biomass can be processed to form either a gas or a liquid "biofuel" that can then be used efficiently in a boiler or a combustion turbine. The Northwest Florida Renewable Energy Center (NWFREC), LLC, a new electricity provider in Florida, is proposing the Port St. Joe Power Project (the Project) as a biomass-based energy facility. Specifically, biomass will be gasified, and the product gas that is produced will be combusted in energy-efficient, combined cycle combustion turbines to produce electricity. The proposed project will generate a nominal net 55.4 megawatts (MW) of electricity.

Biomass gasification units such as the ones being proposed by NWFREC represent an excellent opportunity for the State by providing a reliable, renewable energy source, as well as helping to curb the State's GHG emissions. In addition, projects such as this will help Florida's utilities meet Executive Order No. 07-027, which proposes a 20 percent renewable portfolio standard (RPS).

This application contains the information required by Florida Department of Environmental Protection (FDEP) Form No. 62-210.900(1), Effective: 3/11/10, Application for Air Permit — Long Form. This air application report is divided into the following major sections:

- Section 1.0 provides the Project introduction;
- Section 2.0 presents a description of the Project;
- Section 3.0 provides a description of individual emission units and controls;
- Section 4.0 provides a review of the air requirements applicable to the Project;
- Section 5.0 provides the results of the Project's air quality impact analysis; and
- Attachment: FDEP Form No. 62-210.900(1), Application for Air Permit — Long Form.

2.0 PROJECT DESCRIPTION

NWFREC is proposing to construct a biomass-based electrical generating power plant at the Port St. Joe Industrial Park. The proposed project will generate a nominal net 55.4 megawatts (MW) of electricity. Construction is proposed to commence in August 2011, with a proposed in-service date of January 2013.

The project consists of a biomass fuel “wood chips” delivery/handling system, a biomass gasification system, a biomass dryer, a gas cleanup system, three gas combustion turbines, three heat recovery steam generators (HRSGs), condensing steam turbine generator, an auxiliary natural gas-fired package boiler for start-up use only, an emergency flare system, cooling towers, and auxiliary support equipment such as air systems. The biomass fuel “wood chips” will be chipped to size and screened at a remote location. The fuel preparation process will be owned and operated by others. Biomass fuel will be delivered via truck to the site at a rate of approximately 45 trucks per day.

At the power plant, the trucks will be unloaded via a truck receiving system equipped with two 75-foot platforms. The fuel is then conveyed, via a covered belt conveyor, to the fuel storage pile. The fuel storage pile will contain 10 to 14 days of fuel storage.

From the fuel storage pile, the fuel will be conveyed to a dryer where the moisture is reduced from as high as 45 percent to approximately 23 percent. Leaving the dryer, the fuel will be conveyed via a covered conveyor system to the gasification process area where it is stored in a metering/storage bin. Approximately 900 tons per day (dry basis) of biomass will be fed to the gasifier.

In the gasifier, product gas is formed from the introduction of biomass fuel, which is rapidly pyrolyzed in an oxygen-starved environment by hot sand (olivine). During this process, the olivine temperature diminishes, while the breakdown of the fuel results in the production of char particles (carbon), product gas and a small amount of condensable organic compounds (tars). The resultant char is separated from the reheated olivine via a dual two-stage combustor cyclone. The olivine and char are recirculated to the combustor where the char is burned and serves as a fuel source to reheat the circulating olivine. The reheated olivine is then transported back to the gasifier to supply the energy necessary for the gasification of the incoming wood feedstock.

Product gas from the gasifier is directed to the gas cleanup system for removal of impurities prior to utilization in the three Solar Model T-130 combustion turbines (CTs). The CTs will produce 47.1 MW at an average inlet temperature of 55° F. This average temperature will be maintained by the use of inlet air chillers. Exhaust gases from the CTs will pass through three HRSGs to generate high-pressure steam. The high-pressure steam generated using the HRSGs will be piped to a steam turbine generator to produce 19.6 MW at an average atmospheric temperature of 59° F. The parasitic electrical loads are estimated to be 11.3 MW. Therefore, the net electrical power available at an average inlet turbine air temperature of 55° F is 55.4 MW. The typical product gas composition is provided in Table 2-1.

2.1 Description of Emission Units

The following sections provide a more detailed discussion of the processes and emission units associated with the Project. The Project location and site map is provided in Figure 2-1. A proposed project site layout is presented in Figure 2-2. A process schematic of the entire process, from delivery of feedstock to the power generation block, is provided in Figure 2-3, highlighting the emission points. Figures 2-4 and 2-5 provide more in-depth diagrams of the material handling operations. Figure 2-6 provides proprietary/confidential gasification process Information and is submitted under separate cover.

2.1.1 Material Handling Description

2.1.1.1 Biomass Stackout

The feedstock material handling process associated with fuel delivery (stackout) is depicted in Figure 2-4. All woody biomass will be delivered to the project site via truck. The truck receiving system will be equipped with two 75-foot platforms dumping into two 5,000-cubic foot receiving hoppers. The hoppers will have a very slow moving chain drag to minimize dust. The hoppers will have a discharge rate capability of 150 tons per hour (TPH). Tramp metal will be removed using a suspended self-cleaning magnet from the material stream prior to stockpiling the fuel. From the bottom of the two collection hoppers, the wood chips will be discharged onto a take-away belt conveyor. Material will discharge from the take-away conveyor into a horizontal scalping screen. Any oversized materials will be directed to a vertical hammer hog designed to produce 2-inch minus material. The hog and ancillary conveyors will be supported in a common tower with applicable chute work and dust collection with baghouse. Material will discharge from the hog onto a covered collection conveyor and then transition to the circular stacker.

The circular stacker will form a circular kidney shaped pile at a rate of 300 TPH. The collection conveyor will deliver material to a fully automated stockpile. The stacker will be capable of automatically building a circular stockpile. The feedstock will be evenly distributed in piles up to an average of 40 feet high. The stockpile will have a storage capacity of 2 million cubic feet. The stacker reclaimer will include on-board controls and the stacker reclaimer will be designed to meet operational and structural specifications.

2.1.1.2 Biomass Reclaim

The feedstock material handling process associated with fuel reclaim is depicted in Figure 2-5. Biomass will be reclaimed via and stacker reclaimer from the storage pile via a drag chain to a covered Reclaim Conveyor No. 1. Reclaim Conveyor No. 1 will transfer the material to covered Reclaim Conveyor No. 2 and from Reclaim Conveyor No. 2 the biomass will be transported to Supply Conveyor No. 3, which is controlled by a baghouse. Prior to entering the powerhouse the fuel will be conveyed via Supply

Conveyor No. 3 to a dryer where the moisture is reduced from as high as 45 percent to approximately 23 percent. Covered belt conveyors will then transport the feedstock to a 12-hour storage silo (day bin) adjacent to the gasifier. The belt conveyors will be equipped with belt covers to protect the material from the weather and to prevent the wind from blowing material off of the conveyor belt during transport to the storage silo. Material will be reclaimed from the storage silo via an internal screw discharger, which will deposit the material on a belt conveyor contained primarily inside the silo structure. This belt conveyor will transfer the wood fuel to a vertical elevator that will discharge the fuel via an enclosed chute system to the gasifier fuel feed bin. Approximately 900 tons per day (dry basis) of biomass will be fed to the gasifier. All transfer systems from conveyor to conveyor employ totally enclosed head boxes, chutes, and skirt board systems to contain the fuel and any dust that may be produced at the transfer points. Particulate emissions from these transfer points are kept to a minimum through special designs. The feed bin has a bin vent on top of it to filter the air displaced by transfer of wood into the bin. In addition, all conveyors will be covered to reduce particulate emissions and, as depicted in Figure 2.5, a baghouse will control emissions from the day bin and from transfer of material from the day bin to the bucket elevator.

2.1.2 Gasifier System

Figure 2-6 provides a schematic diagram of the gasification process. The gasifier, combustor, cyclones and baghouse are the primary equipment components of the gasification process. Within these components, circulated olivine, a sand-like material is used as a heat transfer medium to support the reactions occurring in the gasifier and combustor. In addition, there are small natural gas-fired start-up burners associated with the gasifier and combustor. These small burners are more fully described in the section addressing startup emissions. It is estimated that there will be approximately 6 startups per year and that the amount of natural gas to be fired will be minimal, at less than 5 percent of total operating hours.

2.1.2.1 Gasifier

In the gasifier, product gas is formed from the introduction of biomass fuel, which is rapidly pyrolyzed in an oxygen-free environment by hot olivine. Steam is used in the gasifier to provide initial fluidization to begin olivine circulation through the system. Olivine recirculation starts when the vessel temperature has reached approximately 800 °F. The recirculating olivine provides the majority of thermal energy to heat up the gasifier. The gasifier must be heated to at least 1,300 °F prior to the introduction of wood so that the pyrolysis reactions can take place without producing excessive amounts of tar. Once these reactions begin, the resulting product gas provides the primary motive force for the conveying of the olivine and char through the gasifier vessel. Air is gradually reduced once wood feed has started, and is completely turned off once 1,300 °F is reached.

During this process, the olivine temperature diminishes, while the breakdown of the fuel results in the production of char particles (carbon), product gas and a small amount of condensable organic compounds (tars). The resultant char and olivine are separated from the gas stream exiting the gasifier in the dual two-stage gasifier cyclones. Product gas from the gasifier is directed to the gas cleanup system for removal of impurities prior to utilization in the three Solar Model T-130 combustion turbines (CTs). The product gas contains hydrogen sulfide, which is scrubbed out downstream in the gas cleanup system, using an aqueous scrubber. The formation of hydrogen sulfide in the gasifier, in effect, minimizes the amount of fuel sulfur that subsequently enters the combustor.

2.1.2.2 Combustor

At the gasifier exit, the product gas is separated from the olivine and unpyrolyzed char. The char, which is separated out with the olivine in the cyclone, is carried into the combustor. The char contains pyrophoric carbon at 55 percent by weight, 5 percent hydrogen, and 40 percent ash. Air is introduced into the combustor to support the combustion of the char particles with the resultant release of thermal energy, providing additional heat to the recirculating olivine. The reheated olivine is then transported back to the gasifier to supply the energy necessary for the gasification of the incoming wood feedstock.

The combustor cyclone separates the olivine from the flue gas and ash before sending the olivine back to the gasifier. The efficiency of the combustor cyclone is greater than 99 percent removal, so that the loss of olivine from the entire system is minimized. The flue gas, smaller ash and traces of fine olivine particles remain entrained in the gas and proceed to the ash cyclone. Due to the very high efficiency of the combustor cyclone, the targeted ash removal efficiency of the ash cyclone is ~85 percent. The ash cyclone is followed by a baghouse, which removes >99 percent of the remaining particulate before exhausting to the atmosphere.

It is important to note that the flue gas from the combustor contains very little sulfur, as the organic sulfur remains in the product gas as hydrogen sulfide. This is because the pyrolysis process in the product gas gasifier operates in a reducing environment in the absence of oxygen. As a consequence, organic sulfur compounds in the wood decompose into hydrogen sulfide. This component of the gas stream is ultimately reduced in the product gas cleanup system to produce a product gas H_2S concentration of less than 5 ppm.

Ash, essentially wood ash, is a byproduct of the gasification process and must be continuously removed and disposed of off-site as a non-hazardous material.

The ash will be collected in a series of primary and secondary cyclones as the flue gas exits the gasifier combustor. It will drop through the cyclones into an ash hopper and will be quenched with water to both lower the temperature for handling and control (PM) dust emissions. When the hopper is full, the ash will exit the hopper from the bottom into a truck then covered to leave the site for disposal. The air application has accounted for emissions from these described activities. Tars that are recovered are recycled back to the combustor and are not "handled" (i.e., they are contained within a closed loop system) during normal operation.

In addition, it is estimated that about 300 lbs of makeup olivine may be required per day. It is currently proposed that olivine be delivered by truck, and unloaded pneumatically into a storage silo. The silo would be equipped with a baghouse for particulate control. However, it is possible that the use of super sacks may be as efficient as and less costly than a pneumatic unloading system. Final details will be provided when available.

2.1.3 Gas Cleanup

Product gas from the gasifier, after exhausting through several cyclones, is directed to the gas cleanup system. Tar is formed in the gasifier and includes a wide spectrum of organic compounds consisting of several aromatic rings. Tars are often categorized as "heavy" and "light" tars. The gas cleanup system is designed primarily to remove these tars from the product gas, after exiting the gasifier and before going to the combustion turbines, but also includes components for removal of other impurities. These include:

- Particulates;
- Organic impurities (tars mentioned above);
- Inorganic impurities, such as NH_3, HCl, H_2S; and
- Volatile (alkali) metals.

The cleanup system will first remove the dust particles at temperatures > 752°F (400°C) to avoid condensing tars and water. Cyclones will be used to remove these dust particles. Tars are removed next at temperatures above the water dew point. Inorganic impurities can be removed in an aqueous scrubber. The key principle of the tar removal system is to carry out tar removal above the water dew point, to avoid generating an aqueous effluent with a high organic content.

Tar removal is accomplished in a two-stage scrubber utilizing special scrubbing oil. The heavy tars are removed in the first scrubber, condensed, separated from the scrubbing oil and recycled to the combustor. A wet electrostatic precipitator is used to collect microscopic tar and oil droplets before the next stage of scrubbing. The light tars are similarly scrubbed with different scrubbing oil. The light tars are separated from the scrubbing oil and also recycled to the combustor. Recycling of the tars to the combustor contributes to the energy efficiency of the gasification process and further reduces potential NO_X emissions from the combustor. Finally, NO_X is further minimized by the manner in which the fuel bound nitrogen is converted to ammonia (NH_3) rather than NO_X in the gasifier. As stated earlier, ammonia is one of the inorganic impurities ultimately removed from the product gas in the gas cleanup system.

Following the two-stage tar removal process, the fuel gas is cooled and scrubbed with water to remove ammonia, then scrubbed with sodium hydroxide solution to remove HCl and H_2S. Any vapor phase heavy metals are also condensed and removed in this step. The clean fuel gas at about 110 degrees F is then ready to be compressed for use as gas turbine fuel.

2.1.4 Power Generation

2.1.4.1 Gas Turbines

The power generation component of the Project is a gas-fired 66.7 MW (gross)/ 55.4 MW (net) combined cycle generation facility. The combined cycle system will be fired with a product gas derived from wood waste biomass through the proprietary gasification process discussed earlier. Power will be generated by three Solar Model T-130 combustion turbines (CTs), with a maximum heat input of 156.2 MMBtu/hr (LHV) for each CT when firing product gas (100 percent capacity, 55°F). The three gas turbines will produce approximately 15.7 MW each. The projected heat rate for the power generation facility, including the product gas process, is estimated at 9,878 Btu/kW-hr.

A start-up compressor will be provided to supply high pressure natural gas to start up the gas turbines. As stated earlier, it is estimated that there will be approximately 6 startups per year. Therefore, no more than 750 hours of operation on natural gas are requested per year. The NWFREC would also like to request the capability to use ULS fuel oil or biofuel for startup purposes. The gas turbine fuel feed will be switched over to product gas when the turbines are operating in a stabilized condition. Product gas from gas cleanup at approximately 110°F and 10 psig will be split to the three compression and gas turbine trains. The product gas will be compressed in a two-stage compressor to feed each gas turbine.

2.1.4.2 Heat Recovery Steam Generators

Each of the gas turbine exhaust streams will be routed to a dedicated HSRG, to recover the energy in the gas turbine exhaust stream. Steam generated in the three HSRG units will be combined with steam generated in the gasifier island and sent to a steam turbine generator. The exhaust from each HSRG is routed to a selective catalytic reduction (SCR) system for NO_X removal and then to a stack for discharge to the atmosphere.

Aqueous ammonia is added to the SCR for the NO_X removal reaction. Aqueous ammonia will be delivered by truck or rail car. Truck delivered aqueous ammonia will be transferred to an onsite storage tank. If rail car is utilized for delivery of aqueous ammonia, then the rail car storage vessel will remain onsite until a replacement is needed. There will be negligible ammonia emissions from storage tank or rail car breathing losses.

2.1.4.3 Steam Turbine

The high-pressure steam generated using the HRSGs will be piped to a steam turbine generator to produce approximately 19.6 MW at an average atmospheric temperature of 59° F. Additional onsite power will be required for the power island and for compression, as well as for product gas cleanup, the gasifier process and the fuel yard. The parasitic electrical loads are estimated to be 11.3 MW. Therefore, the net electrical power available is approximately 55.4 MW.

2.1.5 Utilities and Infrastructure

2.1.5.1 Auxiliary Boiler

A natural gas-fired auxiliary boiler will provide steam as the start-up conveying medium to begin olivine circulation through the gasifier. The steam also aids in increasing the gasifier temperature to 800°F so olivine circulation can be started. Additional steam will be used to preheat the steam turbine generator during start-up. The boiler, rated at approximately 62 MMBtu/hr, will be operated for less than 500 hours per year.

2.1.5.2 Cooling Tower

Cooling towers will be required for the steam turbine and for the cooling of compressor gases. The wet surface air condenser (~7,050 gallons per minute [gpm]) is the condenser for the steam turbine provided in the project and employs a different technology than a traditional surface heat exchanger (condenser) and cooling tower. The traditional steam turbine heat exchanger (condenser) and cooling tower employ a two-stage method for condensing the steam for both latent and sensible heat rejection. The wet surface air condenser uses one stage that is latent heat rejection. This provides a closer approach to the wet bulb temperature than other methods and is more thermally effective. The air is drawn over the surface of the steam condenser tubes which are sprayed with recirculating water.

In a traditional cooling tower, such as the one to be used for cooling of compressor gases, the cooling water is sprayed onto surfaces and cooled by evaporation of air drawn across the surfaces. This water (~3,800 gpm) is then used in a heat exchanger to cool or condense the fluid. The mechanics of the two different types of equipment account for the difference in their drift rates. Particulate emissions from each of the two cooling towers will be controlled by specifying drift eliminators that will result in a low drift rate (0.002 and 0.005 percent drift, respectively).

2.1.5.3 Flare System

A safety vent and flare system, located downstream of the heat recovery section of the gasification plant, provides a means for emergency venting of the product gas to a flare. There are three operating conditions under which the flare system may potentially be needed: startup, planned shutdown and emergency shutdown (i.e., in the event of a gasifier trip). The flare system is provided with a pilot fuel to continuously operate the flare pilots. The large combustion chamber in each of the two flares provides a stable environment to burn the gas produced during process upsets.

2.2 Proposed Operating Modes

2.2.1 Startup and Shutdown Modes

The expected startup and shutdown procedures for the Project are presented in the following paragraphs. The procedures address operation of two separate components of the Project: 1) the gasification process and, 2) the power block. A full description of the procedures is not provided here, as it contains much proprietary information not germane to air emissions. A summary of estimated annual emissions from startups and shutdowns is presented in Table 2-2.

2.2.1.1 Gasifier Operation

Emissions vary depending on whether the system is in start-up, normal operation or shutdown mode. The modes are discussed individually in the following paragraphs.

Start-up. During start-up, gasifier off gas is routed to the flare. The gasifier and combustor systems are heated to the desired temperature using natural gas-fired burners. The combustor burner is rated at 17 MMBtu/hr and the gasifier burner is rated at 25 MMBtu/hr. Sparging and fluidizing flow is started to begin circulating sand and to bring the sand inventory to the desired temperature. After reaching a gasifier temperature of 1,000 °F feedstock flow is started, the burner duty is reduced. When the gasifier is in a partial oxidation mode, the gasifier air flow is reduced as the gasifier reaction provides the gas velocity required for sand circulation. Steam flow and feedstock flow are ramped up to design rates to avoid overheating. When steam and wood rates have stabilized and the oxygen content in the gasifier is near zero, at this point the product gas can be rerouted from the flare to the gas cleanup system.

Shutdown. There are two shutdown scenarios:

- Emergency shutdown for power outage; and
- Routine Shutdowns for annual turnarounds and unanticipated, but orderly short shutdowns.

The routine shutdowns are of two types:

- Short shutdowns followed by “hot” starts, where the refractory lined vessels and ductwork remain hot and do not require slow heat up rates.
- Longer shutdowns, where the refractory lined vessels and ductwork cool down to the point where slow reheating is required. This typically will happen twice a year, with refractory rework part of the list of tasks to be performed during the shutdown.

Estimates of emissions for shutdowns are determined only for NO_X and PM, since the emissions for the other constituents, such as VOC and SO_X are already very low.

Emergency shutdown is defined as total loss or shutdown of incoming electrical power, so that all the process motors stop in a few seconds. Another term used to describe this is an emergency electrical trip. Emergency backup electrical power will be available to provide electrical power to the process control system, and a limited number of other electrical users. In general, gas flow through the plant will ramp down rapidly to zero in a space of 3 to 4 minutes.

An integral part of the emergency shutdown system is the inert gas purging system. This system provides for storage of five times the volume of the gasifier and its associated cyclones. Upon an emergency trip, the product gas will be routed to the flare for several minutes, until the flow rate of gas drops off to essentially zero. At this point, the inert gas system is activated by the emergency electrical power system, and forces an inert gas through the gasifier and its cyclones in sufficient volume that any combustible gases in the vessels are reduced in concentration. The reduction in the concentration is sufficient to dilute the combustible gases below their lower explosive limit in an ambient air environment. An ancillary aspect is to reduce the concentration of oxygen in the gasifier equipment to a level where it will not support combustion, which is nominally below a 5 percent by volume concentration.

Typically, the inert gas system will contain nitrogen at elevated pressure in the gaseous state, so that the full volume of the inert gas system can be charged through the gasifier and its associated equipment in less than one minute. Specifics on this system are currently the subject of preliminary engineering design. Such an emergency shutdown has an unknown frequency of occurring, since it can be tripped by natural phenomena such as a thunderstorm.

For an emergency shutdown using inert gas, the gas should be flared to purge the system of flammable gases. During the initial part of the flaring, there will be a substantial flow of flammable gas to the flare, followed by a rapid decrease in the rate of burning flared gas as it is displaced by inert gas. There will be some continued production of gases and pyrophoric char in the gasifier after the initial purging of the vessels with inert gas. Continued purging with sparge gas — inert gas with less than 5 percent oxygen— will be performed, and the CO and CO_2 levels monitored. The drop in the CO and CO_2 levels to steady, low levels will indicate that the residual materials in the gasifier that could burn, have been burned out by the sparge gas.

Routine shutdowns will generally occur more often over a year than emergency shutdowns, and are planned in advance and thus are orderly. These are short shutdowns that do not require cooling of the refractory vessels. Duration can be from minutes to a number of hours. The basic sequence for the gasifier is:

- Prepare system for shutdown by reducing wood flow rate to 50 percent of design rate.
- Start the gasifier blower, opening the bypass to minimize initial airflow into the gasifier.
- Turn off the wood flow, and monitor the product gas flow rate, and CO and CO_2 composition of the product gas.
- Gradually increase the gasifier blower airflow to the gasifier, using the CO and CO_2 levels to determine when all the wood and carbon have been burned out of the gasifier.
- At the same time, gradually reduce the steam flow to the distributors until it is reduced to zero.
- Maintain an upward adequate airflow velocity during the transition from steam to air.
- Stop airflow to the gasifier when the CO and CO_2 levels indicate all the carbon has been burned out of the gasifier.

The combustor has no sequence; airflow is maintained at the full design flow rate to ensure fluidization. The combustor blower is turned off when the gasifier blower is turned off.

Wood NO_X emissions during the shutdown will occur for a 3 to 4 minute period while the wood is being burned out with air. For 3 minutes, the amount of wood will be at 50 percent of the feedrate, which is about 37,500 lb/hr, or 625 lb/minute. Under the worst case conditions mentioned in AP-42, of 33 lb/hr NO_X per ton of feedstock (Table 1.1.3 in AP-42, for a bituminous cyclone furnace), the NO_X emissions thus could be as high as 10.31 lb/minute. For three minutes, this results in about 30.94 lbs of NO_X. Assuming four such shutdowns during the year, the NO_X emissions from the wood will be on the order of 123.75 lb/yr (0.06 tpy).

PM emissions from olivine may occur during this period from the gasifier, since the circulation of olivine will still be occurring, although at reduced rates. Determining the exact amount of PM emissions during the routine shutdown is a complex calculation. However, if it is assumed that the entire amount of olivine in the system inventory is lost out the flare stack during this period, the maximum potential loss can be calculated. Attrition tests have indicated that the attrition loss of olivine from a recirculating olivine system is about 0.1 percent of the total inventory over a 120 day operating period. Since the amount of time for the turnaround shutdown and cool off will be at most one day, the total amount of olivine which could be lost during a single day is on the order of 0.1 percent/120 or 0.0008 percent of the olivine inventory. The inventory is estimated to be on the order of 30,000 lbs. A 0.0008 percent loss results in 0.24 lb. The actual amount should be less, since the recirculation of olivine will not go on for a full day.

For turnaround shutdown, the sequence here is the same, except that the gasifier and combustor blowers remain on to help cool down the equipment faster. Their flow rates are reduced to where the cooling rate on the refractory is less than 100°F/hr. There is no fired equipment used during this final period, so there are no NO_X or VOC emissions from combustion. The emissions will be about the same as listed above for wood NO_X emissions.

Since there are two turnaround shutdowns per annum, the NO_X emissions from the wood during turnaround shutdown should be no more than about 50 lbs/yr, and in all probability will be less than one-half that amount. PM emissions from olivine may occur during this period from the gasifier, since the circulation of olivine will still be occurring, although at reduced rates.

Since the turnaround shutdown will go on for a much longer period than a routine shutdown, the amount of emissions expected should be higher. However, the estimate already developed assumes that all the olivine is lost, and it uses a 24-hour period as a basis. This is so conservative that this approach is reused to estimate the amount lost during the turnaround, then increased by a factor of 10 to consider the longer period of time the turnaround shutdown runs its blowers. The inventory was estimated to be on the order of 30,000 lbs. A 0.0008 percent loss results in 0.24 lb. Multiplying this by ten yields 2.4 pounds or, for two annual turnarounds, 5 pounds per year.

Therefore, based on the startup and shutdown procedures described above, it is requested that up to 4 hours of allowable excess emissions be provided in a 24-hour period to address anticipated emissions during startup and shutdown events.

2.2.1.2 Power Block Operation

Emissions calculations for the startup and shutdown emissions from the power block, as well as the gasification operation are presented in Table 2-2. The start-up and shutdown sequencing required for the biomass gasification combined cycle operation will require an excess emission allowance greater than two hours provided under the FDEP rules. During cold start-up, the operating load of the CTs is limited by the amount of steam that can be accepted by the steam turbine and will result in excess emissions. The excess emission allowance requested for the power block is similar to that of other combined cycle projects, with the exception that this is a gasification process. The proposed condition for power block follows:

> *"Excess Emissions Allowed from Combined Cycle Combustion Turbines: As specified in this condition, excess emissions resulting from startup, shutdown, fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.*
>
> a. *Steam Turbine/HRSG System Cold Startup:* For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed four (4) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

b. *Gas Turbine/HRSG System Cold Startup:* For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

c. *Steam Turbine/HRSG System Warm Startup:* For warm startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three (3) hours in any 24-hour period. "Warm startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting more than 8 hours and less than 48 hours.

d. *Shutdown Combined Cycle Operation:* For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three (3) hours in any 24-hour period.

e. *Fuel Switching:* For fuel switching, excess emissions shall not exceed two (2) hours in any 24-hour period.

As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions for each CT only for specifically defined periods of startup, shutdown, fuel switching and documented malfunction of the gas turbines or the SCR systems. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

2.2.2 Combined Cycle Operation

The Project will be configured as a 3-on-1 combined cycle unit for base load service. The CTs will use combustion technology when firing product gas and natural gas/biofuel (during startup) to minimize NO_X formation. An SCR system will be installed in each HRSG to further reduce NO_X emissions. Product gas will be the primary fuel and natural gas will be limited to the equivalent of 750 hours per year (hr/yr) to address startups.

For the Solar T-130 CTs, the maximum heat input is 156.2 MMBtu/hr (LHV) for each CT when firing product gas or natural gas (100 percent capacity, 55°F). The corresponding fuel usage is about 358,682 cubic feet per hour (cf/hr) of product gas (based on a heating value of 435 Btu/cf- LHV) or about 159,388 cf/hr of natural gas for each CT (based on a heating value of 980 Btu/cf- LHV). Maximum potential annual fuel usage at 55°F turbine inlet temperature would be about 9.4 billion cubic feet per year (cf/yr) of product gas for the 3-on-1 combined cycle unit using the Solar T-130 Class CTs. Assuming no more than 750 hr/yr of natural gas-firing for startups, annual natural gas usage would be approximately 359 million cf/yr. This represents approximately 6 startups per year and less than 10 percent of total operating hours.

Of course, for every hour of natural gas firing, there will be one hour less of product gas firing reflected in the above figures.

Plant performance for each of the CTs under consideration for the Project was developed for product gas-firing at 100 percent load and turbine inlet temperatures of 55°F, representing average annual conditions.

3.0 PROPOSED SOURCE EMISSIONS AND CONTROLS

Estimated maximum hourly emissions, annual emissions and proposed control technology information representative of each emission unit during normal operation are provided in the following sections. Table 3-1 provides a summary of total project emissions, including hazardous air pollutants. Individual process units were described in detail in Section 2.0 of this report. The following is a summary listing of the process units considered in this emissions evaluation:

- Power Block, consisting of CT Trains 1A, 1B and 1C;
- Gasifier Combustor
- Material Handling (i.e., feedstock delivery, conveying and storage);
- Feedstock Dryer;
- Auxiliary Boiler;
- Flare Systems; and
- Cooling Towers

The above-listed emission units can be located on Figure 2-3 (Overall Process Schematic) and referenced to ID Nos. 1 through 7.

3.1 Power Block

The CT/HRSG case operating at base-load is presented in Table 3-2 for product gas firing in combined cycle mode. Detailed vendor information is provided in Appendix A. These units are identified as ID Nos. 1A, 1B and 1C on Figure 2-3. Plant performance for each of the CTs was developed for product gas-firing at 100 percent load and turbine inlet temperature of 55°F. This analysis assumes that the maximum emission rate occurs at base load. On an annual basis, this analysis assumes that the CTs operate 8,760 hours per year.

Emissions of CO and VOCs will be minimized through good combustion practices and the use of an oxidation catalyst system. SO_2 emissions will be minimized through utilization of natural gas during startups and the gas cleanup system on the product gas.

When firing product gas, NO_X emissions from the turbines will be controlled using good combustion techniques and SCR systems, to approximately 15 parts per million or less by volume dry (ppmvd), corrected to 15 percent O_2. The SCR reactors will be located in each HRSG to provide the proper operating temperature range for the required reaction between ammonia and NO_X to achieve additional NO_X reductions. The ammonia handling system will include diluent air blowers (each sized for 100 percent capacity), ammonia flow control and measurement devices, an ammonia/air mixing chamber, distribution header(s), and an ammonia injection grid (AIG). Overall control of the system will be by a distributed control system (DCS).

The only significant sources of HAPs from this project would result from combustion in the combustor associated with the gasifier, as well as from combustion within the combustion turbines in the power block. HAP emission estimates are provided in the air application for the combined cycle power block. These estimates are based on the use of natural gas emission factors in AP-42. The NWFREC has conducted further research on the availability of HAP emission data specific to this combustion technology and this product gas, including discussions with the turbine vendor. No data has been found that would be more representative than the estimates previously provided. As further background on this issue, the turbine vendor (Solar Turbines) believes that some organic HAPs, such as formaldehyde, correlate with CO emissions. A comparison was made between the CO emissions based on AP-42 natural gas-firing and the Solar estimates that were based on the combustion of the product gas, as follows:

AP42 -- uncontrolled CT natural gas emission factor = 0.082 lb/MMBtu.

Solar – 12.6 lb/hr CO / 232 MMBtu/hr = 0.054 lb/MMBtu

Therefore, as some of the organic HAPs, such as formaldehyde, are products of incomplete combustion, similar to CO, the above comparison could infer that the use of AP-42 emission factors, at least for organic HAPs, may provide a conservative emission estimate. CT HAP emission estimates are presented in Table 3-3. It is assumed that the product gas composition, relative to the composition of natural gas, allows for a similar application of these factors.

3.2 Gasifier/Combustor System

Table 3-4 provides a summary of emission estimates from the gasifier/combustor system. This emission point is identified as ID No. 2 on Figure 2-3. A schematic diagram of the gasification process was previously provided in Figure 2-6. The gasifier, combustor, cyclones and baghouse are the primary equipment components of the gasification process. In addition, there are small natural gas-fired start-up burners associated with the gasifier and combustor. These small burners are more fully described in the section addressing startup emissions.

Flue gas from the combustor flows through an additional cyclone, heat recovery exchangers, and a baghouse before exhausting to the atmosphere. Product gas from the gasifier is directed to the gas cleanup system for removal of impurities prior to utilization in the three Solar Model T-130 combustion turbine generators (CTs).

The emissions produced by the combustor have been estimated based on the use of the same emission factors as anthracite coal burned in a conventional fluidized bed combustor boiler.[1] Anthracite was

[1] AP-42 Chapter 1, Section 1.2 for Anthracite Coal Combustion.

chosen because it has a higher carbon content and lower volatile content than lower ranked coals. Since nearly all the volatile components of the biomass are removed in the gasification process and the resultant char is nearly all carbon and ash, anthracite is a reasonable estimate without specific test data.

While the conventional AP-42 factor is considered conservative, char combustion NO_X emissions will be inherently lower because combustion in the combustor will take place at reduced excess air levels as compared to a traditional fluidized bed boiler, which can run 10 to 20 percent excess air by comparison. Nevertheless, an emission factor of 1.80 lb per ton, from AP-42, Table 1.2-1 is utilized to estimate NO_x emissions from the gasifier.

SO_x emissions are a combination of sulfur dioxide, SO_2, with traces of SO_3, sulfur trioxide. Typically, less than 0.1 percent sulfur would be expected in the feedstock. Sulfur, which goes into the product gas or the combustor flue gas, is considered to be primarily derived from the decomposition of organic sulfur sources. In the product gas, the primary sulfur-containing constituent is H_2S, while in the combustor flue gas it will be SO_2. Organic sulfur in the amino acids in the biomass typically runs at a concentration of about 10 percent that of the nitrogen content of the amino acids. From vendor analyses received by NWFREC, sulfur concentrations average around 0.01 to 0.04 percent. For instance, the emission estimate based on a sulfur content of 0.04 percent sulfur would have organic sulfur emissions at 10 percent of this, or 0.004 percent.

Ash will be collected in a series of primary and secondary cyclones as the flue gas exits the gasifier combustor. It will drop through the cyclones into an ash hopper and will be quenched with water to both lower the temperature for handling and control (PM) dust emissions. When the hopper is full, the ash will exit the hopper from the bottom into a truck then covered to leave the site for disposal. The air application has accounted for emissions from these described activities. Tars that are recovered are recycled back to the combustor and are not “handled” (i.e., they are contained within a closed loop system) during normal operation.

Filterable PM is that material which will ultimately exit the baghouse. Condensable PM consists of fine droplets, typically sulfates and nitrates. Condensables are not significant in the analysis, as the constituents that would comprise condensable PM are controlled in the reactions between the gasifier and the combustor, as well as the downstream gas cleanup system. Emissions from the gasifier combustor system are provided in Table 3-4.

3.3 Material Handling System Description

Emission estimates from the material handling system are summarized in Table 3-5. Detailed emission tables including controls and control efficiency are provided in Appendix B. This component of the process operation is depicted by ID No. 7 on Figure 2-3. In addition, a more detailed process flow diagram of the handling system showing fugitive particulate emission points are presented in Figures 2-4 and 2-5.

The ash and olivine transfer and storage systems are depicted in Figure 2-6. Woody biomass feedstock preparation will occur at a remote site that will be owned and operated by others. At this remote area, the feedstock will be sorted, screened and chipped to size. Although some leaves and small branches may inadvertently find their way into the feedstock, the focus is on producing wood chips from the woody biomass. Fuel availability appears to be both predictable and plentiful going forward, with the only real concern involving transportation costs. NWFREC is being somewhat opportunistic in their feed stock approach, meaning that they will contract for some supplies, but will also take advantage of more economic market opportunities when possible. The advantage of the gasification technique is that most biomass will react the same. Some of the available feedstock types that are categorized as woody biomass, and that are proposed for the NWFREC, include the following:

- Hogged Fuel;
- Processed Butt Cuts and;
- A Fuel Crop.

The hogged fuel is material that comprises land clearing debris that has either been pre-processed, run through a tub grinder, or a horizontal mill at a specific private forest clearing site. The butt cuts are round wood residues that are either of oversized or undersized non-processible materials from post or pole manufacturers. Finally, the fuel crop is a vegetative biomass being considered as a potential feedstock.

A detailed description of the material handling system is provided in Section 2.1.1. Any oversized materials will be directed to a vertical hammer hog designed to produce 2-inch minus material. The hog and ancillary conveyors will be supported in a common tower with applicable chute work and dust collection with baghouse. Emissions are primarily associated with the transport and storage of the biomass feedstock on the site. The feedstock storage pile will utilize water suppression to control fugitive particulate emissions. The feedstock received will have a moisture content of 30 to 40 percent, minimizing the potential for fugitive dust. In addition, all conveying systems will be enclosed.

The wood-handling industry is well aware of the tendency of an un-managed pile of wood-waste to overheat and result in spontaneous combustion. Accordingly, BEH’s Best Management Plan (BMP) to manage the fuel pile will have as its goals:

- Avoidance of conditions giving rise to spontaneous combustion, supported by the fire control systems to be provided after approval by State and insurance entities, which specifically will provide fuel pile fire control;
- Minimization of fugitive dust emissions, also using fuel pile fire protection facilities for dust suppression as required; and

- Blending of the various fuels received to ensure reasonably consistent fuel properties as delivered to the gasifier.

The following preliminary BMP for fuel handling dust control is subject to the provision of further detail and adjustment during the project's detailed design phase to reflect final equipment selection:

Measures to Minimize Spontaneous Combustion.

- Daily inspection for fire hazards, plus video surveillance;
- The stack-out/reclaim plan will ensure reclaim of older material to avoid accumulation of fuel with a significant age. The first-in/first-out (FIFO) procedure will be slightly modified to ensure blending of older and newer fuel for consistent fuel properties. The equipment is only capable of handling 20,000 wet tons or about a 12 day supply of fuel. This will ensure a quick turnover of feedstock in order to make more room for deliveries. Despite the available onsite storage space, the NWFREC does not have the necessary equipment to move fuel from another pile into the dryer and the gasifier storage bin;
- Use of daily inspections and fire-water cannons, mounted on elevated structures, together with mobile equipment to uncover and rapidly extinguish any smoldering materials found; and
- The size of the fuel storage pile will not exceed the design value – this is a primary control measure, based upon the limited on-site fuel storage of about 2 weeks' worth of fuel. Specifically, the stacker will build a pile in zones averaging up to 40 feet high and the reclaimer will start with the first zone built and reclaim the pile down to within two inches of grade.

Measures to Minimize Fugitive Dust.

- The size of the fuel storage pile, about 2 weeks' worth of fuel, minimizes the area subject to wind erosion and reduces the travel time required for mobile equipment;
- Conveyor transfer points are enclosed or partially enclosed;
- Drop points to the fuel storage areas are designed to minimize the exposed drop height;
- Transfer points and fuel bins are equipped with vent filters;
- Under pile fuel reclaimers do not generate fugitive dust;
- Fuel handling equipment is observed daily for proper operation and for maintenance requirements;
- Plant fuel handling personnel will implement a procedure for observing and controlling unplanned fugitive dust emissions, including truck handling and unloading, and dirt or fuel on roads; and
- All major roadways will be paved. Plant personnel will spray, scrape, or otherwise remove dirt or spilled fuel on plant roads.

Storage Pile Management.

- Operational plans will recognize conditions such as high winds likely to result in excessive fugitive dust and will curtail movement of fuel by mobile equipment under such conditions; and
- Mobile equipment will be used to maintain the pile's design shape and to ensure adherence to FIFO in reclaim operations.

3.4 Feedstock Dryer

The dryer is depicted as ID No. 3 on Figure 2-3. Emission estimates for the feedstock dryer are presented in Table 3-6. The dryer will use waste heat (i.e., no combustion involved) at a temperature of ~175 °F and a flow rate of ~110,000 scfm. It is assumed that the feedstock throughput will be approximately 1,285 wet tons per day of wood (based on 30 percent moisture), which would produce 900 tons per day of feed to the gasifier (dry basis).

3.5 Auxiliary Boiler

Table 3-7 presents estimated performance and emissions information for the future auxiliary boiler. This emission unit is designated as ID No. 4 on Figure 2-3. Provisions for an auxiliary boiler are included in the Project design to assist in gasifier and combined cycle startup, if required in the future. Once sufficient quality and quantity of steam is available from the HRSG, steam from the auxiliary boiler is not required. The future steam boiler will be a Nebraska Boiler or equivalent with steam capacity of 50,000 lb/hr and a heat input rating of up to 62 MMBtu/hr. It was conservatively assumed that the annual operation of the auxiliary boiler would be 500 hr/yr or less. The proposed controls for the auxiliary boiler include good combustion practices to limit emissions of NO_X, CO, and VOC. Natural gas is the cleanest fossil fuel and will minimize the emissions of PM and SO_2 to low emission levels. The auxiliary boiler will also limit NO_X emissions using low-NO_X burners. The emission limits and control technology proposed will meet the Florida-specific small boiler BACT requirements (62-296.406, F.A.C.), as well as NSPS Subpart Dc.

3.6 Flare System

A safety vent and flare system, located downstream of the heat recovery section of the gasification plant, provides a means for emergency venting of the product gas to a flare. The two proposed flares are depicted as ID No. 5 on Figure 2-3. There are three operating conditions under which the flare system may potentially be needed: startup, planned shutdown and emergency shutdown (i.e., in the event of a gasifier trip). The flare system is provided with a pilot fuel to continuously operate the flare pilots. The large combustion chamber in each of the two flares provides a stable environment to burn the gas produced during process upsets.

The flare type would likely be of an open design with a height close to 30 feet. Emissions are estimated based on 100 hr/yr of operation and are presented in Table 3-8. A typical composition of the product gas to be flared was previously presented in Table 2-1. This would occur in the event of a process trip or malfunction.

3.7 Cooling Towers

Cooling towers will be required for the steam turbine and for the cooling of compressor gases. The wet surface air condenser (~7,050 gpm) is the condenser for the steam turbine provided in the project and employs a different technology than a traditional surface heat exchanger (condenser) and cooling tower. In a traditional cooling tower, such as the one to be used for cooling of compressor gases, the cooling water is sprayed onto surfaces and cooled by evaporation of air drawn across the surfaces. This water (~3,800 gpm) is then used in a heat exchanger to cool or condense the fluid. Particulate emissions from each of the two cooling towers will be controlled by specifying drift eliminators that will result in a low drift rate (0.002 and 0.005 percent drift, respectively). The mechanics of the two different types of equipment account for the difference in their drift rates. In addition, the total dissolved solids (TDS) content of the cooling water is very low. Estimated emissions are presented in Table 3-9.

3.8 Site Layout, Structures, and Stack Sampling Facilities

A plot plan of the proposed project was previously presented in Figure 2-2 (Project Site Layout). The approximate dimensions of the buildings and structures are also presented in this figure. Stack sampling facilities will be constructed in accordance with Rule 62-297.310(6), F.A.C.

4.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal, state, and local air regulatory requirements and their applicability to the Project. These requirements must be satisfied before the proposed facility can begin construction and/or operation.

The FDEP regulations require any new source to obtain an air permit prior to construction. New sources must meet the appropriate requirements and obtain the required permits and approvals for air pollution sources, including Prevention of Significant Deterioration (PSD) (if major), applicable New Source Performance Standards (NSPS), applicable National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400, F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C., and 40 CFR Parts 60, 61, and 63.

FDEP has nonattainment provisions (Rule 62-212.500, F.A.C.) that apply to all major new facilities located in a nonattainment area. In addition, for major facilities that are located in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The Project is located in Gulf County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment new source requirements are not applicable. There are currently no local air quality regulations more stringent than those at the state level.

4.1 New Source Review (NSR) Requirements

Under federal and Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed, and a pre-construction permit issued. As Florida's EPA approved State Implementation Plan (SIP) includes PSD regulations, the Florida Department of Environmental Protection (FDEP) has PSD approval authority.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 TPY or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. The Project is not classified as any of the listed 28 source categories; therefore, the threshold for a major facility classification is 250 TPY of any pollutant. The project emissions summary, presented in Table 3-1, indicates that all pollutants are below the applicable threshold.

However, on May 13, 2010, the U.S. Environmental Protection Agency (EPA) issued a final rule that establishes an approach to addressing greenhouse gas emissions from stationary sources under the Clean Air Act (CAA) permitting programs. This final rule sets thresholds for greenhouse gas (GHG) emissions that define when permits under the NSR PSD and Title V Operating Permit programs are required for new and existing industrial facilities. This final rule “tailors” the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. The rule establishes a schedule that will initially focus CAA permitting programs on the largest sources with the most CAA permitting experience. The rule then expands to cover the largest sources of GHG that may not have been previously covered by the CAA for other pollutants. Finally, it describes EPA plans for any additional steps in this process.

Step 1. (January 2, 2011 –June 30, 2011)

- Only sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than GHGs) would be subject to permitting requirements for their GHG emissions under PSD.
- For these projects, only GHG increases of 75,000 tpy or more of total GHG, on a CO_{2e} basis, would need to determine the Best Available Control Technology (BACT) for their GHG emissions.
- Similarly for the operating permit program, only sources currently subject to the program (i.e., newly constructed or existing major sources for a pollutant other than GHGs) would be subject to Title V requirements for GHG.
- During this time, no sources would be subject to Clean Air Act permitting requirements due solely to GHG emissions.

Step 2. (July 1, 2011 to June 30, 2013)

- Step 2 will build on Step 1. In this phase, PSD permitting requirements will cover for the first time new construction projects that emit GHG emissions of at least 100,000 TPY even if they do not exceed the permitting thresholds for any other pollutant. Modifications at existing facilities that increase GHG emissions by at least 75,000 TPY will be subject to permitting requirements, even if they do not significantly increase emissions of any other pollutant.
- In Step 2, operating permit requirements will, for the first time, apply to sources based on their GHG emissions even if they would not apply based on emissions of any other pollutant. Facilities that emit at least 100,000 TPY CO_{2e} will be subject to Title V permitting requirements.
- EPA estimates that about 550 sources will need to obtain Title V permits for the first time due to their GHG emissions. The majority of these newly permitted sources will likely be solid waste landfills and industrial manufacturers. There will be approximately 900 additional PSD permitting actions each year triggered by increases in GHG emissions from new and modified emission sources.

NWFREC understands that the EPA has issued a waiver of exemption for biogenic emissions of GHGs for a period of three years; therefore, these NSR requirements will not be applicable to this project.

4.2 New Source Performance Standards (NSPS)

The NSPS are national emission standards, 40 CFR 60, that apply to specific categories of new sources. As stated in the 1977 Clean Air Act Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

4.2.1 NSPS 40 CFR 60 Subpart Da (Electric Utility Steam Generating Units)

This rule applies to combined cycle combustion turbines associated with an integrated gasification combined cycle (IGCC) system if: (1) the turbine is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and (2) the turbine is designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis. "Solid-derived fuel" means "any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquefied coal, synthetic gas, gasified coal, gasified petroleum coke, gasified biomass, and gasified tire derived fuel." The heat input to each of NWFREC's turbines is a nominal 156 MMBtu/hour, which is less than the threshold level of 250 MMBtu/hour. Therefore, this rule does not apply to the combustion turbines. .

4.2.2 NSPS 40 CFR 60 Subpart Dc (Standards for Small Industrial-Commercial-Institutional Steam Generating Units)

The proposed auxiliary boiler will be an affected facility to which this subpart applies, as it will be constructed after June 9, 1989 and will have a maximum design heat input capacity of 100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 10 MMBtu/hr. The proposed use of natural gas and limited operating hours (i.e., 750 hours per year, or less than a 10 percent capacity factor) will easily allow compliance with the applicable standards.

4.2.3 NSPS for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK)

EPA promulgated new NSPS for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK) that commence construction after February 18, 2005. This new final rule was effective on July 6, 2006. The stationary combustion turbines subject to Subpart KKKK, 40 CFR 60 (i.e., 10 MMBtu/hr or greater), are exempt from the requirements of 40 CFR 60, Subpart GG for combustion turbines. Heat recovery steam generators subject to Subpart KKKK are exempt from the requirements of 40 CFR 60, Subparts Da, Db and Dc. The Subpart KKKK emission limits apply not only to the combustion turbines but also to emissions from any associated heat recovery steam generating units.

NO_X emissions for these proposed units (i.e., firing fuels other than natural gas, with a heat input > 50 MMBtu/hr and < 850 MMBtu/hr) are limited by Subpart KKKK to 74 ppmvd corrected to 15 percent O_2 (or 3.6 lb/MW-hr). SO_2 emissions are limited to 0.60 lbSO2/MMBtu heat input 0.90 lb/MW-hr while firing product gas and a sulfur content of no greater than 20 grains of sulfur per 100 standard cubic feet for natural gas-firing. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR Subpart KKKK. There are also applicable notification, reporting, and recordkeeping requirements in the general provisions of 40 CFR Subpart A. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

(a)(1) Notification of the date of construction — 30 days after such date.

(a)(3) Notification of actual date of initial start-up — within 15 days after such date.

(a)(5) Notification of date which demonstrates CEM — not less than 30 days prior to date.

60.7 (b) Maintain records of all start-ups, shutdowns, and malfunctions.

(c) Excess emissions reports — semi-annually by the 30th day following six-month period (required even if no excess emissions occur).

(d) Maintain file of all measurements for two years.

60.8 Performance Tests

(a) must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.

(d) Notification of Performance tests at least 30 days prior to them occurring.

4.2.4 NSPS Subpart Eb (Municipal Waste Combustion Units; Commercial)

Subpart Eb applies to new municipal waste combustor units with a combustion capacity of greater than 250 tons per day of municipal solid waste. Qualifying small power production facilities, as defined in section 3(17)(c) of the Federal Power Act, that burn homogenous waste (excluding refuse-derived fuel) for the production of electricity are not subject to Subpart Eb. The owner or operator of such a facility must notify EPA of the exemption and provide supporting documentation. The Project is a qualifying small power production facility and will use only homogenous woody biomass as a feedstock for the gasifier, with a small percentage of it constituting "municipal solid waste" (e.g., yard trimmings). It is estimated that no more than 30 TPD, quarterly average, would be utilized as feedstock. If appropriate, documentation to support this exemption can be provided to EPA and the Department.

4.2.5 NSPS 40 CFR 60 Subpart CCCC (Industrial Solid Waste Incineration Units)

This rule applies to new commercial and industrial solid waste incineration (CISWI) units, although the definition of "commercial and industrial solid waste incineration units" has been vacated and remanded to EPA. (Natural Resources Defense Council v. EPA, 489 F.3d 1250 (D.C. Cir. June 2007). Without this critical definition, applicability of this standard is indeterminable. In addition, "qualifying small power production facilities" and "chemical recovery units" (conversion of hydrocarbon solids to syngas) are both exempt from this rule. Subpart CCCC is therefore not applicable to the Project's gasifier, at least at this time.

4.2.6 NSPS 40 CFR 60 Subpart RRR (VOC Emissions from SOCMI Reactor Processes)

According to 60.700(a), this subpart applies to a process unit that produces any of the listed chemicals as a product, co-product, byproduct or intermediate. Product is defined as any compound or chemical listed in 60.707 that is produced for sale as a final product as a chemical or for use in the production of other chemicals or compounds. It also states that co-product, byproducts, and intermediates are considered products. Since the Project is not using the product gas to sell as a final product or for use in producing other chemicals or compounds, this regulation does not apply.

4.3 National Emission Standards for Hazardous Air Pollutants (MACT Standards)

The Project is not major for HAPs. The standards under 40 CFR Part 63 are, therefore, not applicable.

4.4 Florida Rules

Florida has adopted the NSR program requirements, NSPS, and NESHAPs by reference. Therefore, the facility is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping as those described in the previous sections.

4.4.1 Rule 62-296.401, F.A.C., Incinerator Rule

The NWFREC has determined that Florida's rule applicable to "incinerators" would not apply to this Project. The Department's rules broadly define "incinerator" as a "combustion apparatus designed for the ignition and burning of solid, semi-solid, liquid or gaseous combustible wastes." The proposed unit is expected to use some waste forms of biomass as a feedstock for the gasifier system (e.g., agricultural waste, clean construction and demolition debris, urban yard trimmings, etc.). The gasifier, however, will use a pyrolysis system (absence of air) to convert biomass to product gas, which is not "combustion" or "ignition and burning." Residual char from the pyrolysis system will be combusted in the chamber associated with the gasifier, but the "char" is not a waste. The product gas produced from the gasifier, also not a waste, will subsequently be combusted in the combustion turbines and duct burners. Therefore, no waste is incinerated through a combustion process, and this rule should not apply.

4.4.2 Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment

Carbonaceous fuel is defined in the Department's rules as solid materials composed primarily of vegetative matter such as tree bark, wood waste, or bagasse. The vegetative matter (biomass) to be used as the feedstock in the primary chamber of the gasifier is not "burned" or combusted. The biomass will be heated with olivine in the absence of oxygen without combustion. The resulting "char" will then be combusted in the second chamber of the gasifier, although the material is not a fuel or "vegetative" matter at that point. The primary “fuel burning” is to occur in the combustion turbines and duct burners, however, the fuel is product gas and not a solid. This rule, therefore, does not appear applicable to the Project.

4.4.3 Rule 62-296.416, F.A.C., Waste-to-Energy

The Department’s rules define the term “waste-to-energy facility” as a facility that uses controlled combustion to thermally break down solid, liquid, or gaseous combustible solid waste to an ash residue that contains little or no combustible material and that produces electricity, steam, or other energy as a result. The term does not include facilities that primarily burn fuels other than solid waste, even if the facilities also burn some solid waste as a fuel supplement. The term also does not include facilities that burn vegetative, agricultural, or silvicultural wastes, bagasse, clean dry wood, methane or other landfill gas, wood fuel derived from construction or demolition debris, or waste tires, alone or in combination with fossil fuel [Rule 62-210.200(331), F.A.C.]. Because silva culture waste is being used as the primary feedstock and product gas is being used as the primary fuel, this rule would not apply to the Project.

4.5 Other Clean Air Act Requirements

4.5.1 The Acid Rain Program

The 1990 Clean Air Act Amendments established the Acid Rain Program to reduce the release of acidic deposition precursors, SO_2 and NO_X. EPA’s final regulations were promulgated on January 11, 1993, and included permit provisions (Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

This Acid Rain Program generally applies to all existing and new utility units. “Utility unit” is defined to mean “a unit owned and operated by a utility … that serves a generator in any State that produces electricity for sale.” “Utility” is defined to mean “any person that sells electricity.” Under these definitions, BEH would be considered a “utility” and the proposed combined cycle turbine units would be considered “utility units.” There are exceptions to the Acid Rain Program for certain types of units (e.g., small units serving generators with nameplate capacities of less than 25 MW, pre-1991 small simple cycle combustion turbines, cogenerating facilities, qualifying facilities and independent power producers with contracts in effect as of 1990, solid waste incineration units, etc.), none of which appear applicable to the proposed project. The Acid Rain Program therefore appears applicable to the Project. Accordingly, applications for an Acid Rain permit and a Certificate of Representation are also included in this air permit application package.

4.5.2 Regional Haze

The Department’s Best Available Retrofit Technology (BART) rule applies to facilities in existence on August 7, 1977, and that have the potential to emit 250 tons per year or more of any air pollutant (Rule 62-296.340, F.A.C.). The Project does not meet these criteria and therefore the BART rule does not apply. Similarly, the Department's Reasonable Further Progress rule applies to units in existence as of August 30, 1999. Therefore, this rule is also not applicable to the Project (Rule 62-296.341, F.A.C.).

4.5.3 Clean Air Interstate Rule (CAIR)

Generally, the CAIR program applies to stationary boilers and combustion turbines that fire any amount of fossil fuel at any time and serve a generator with a nameplate capacity of more than 25 MW, producing electricity for sale. As the nameplate capacities of the individual generators proposed for the Project are less than 25 MW, CAIR is not applicable to this Project. Specifically, each of the three combustion turbines are rated at a nominal 15.7 MW and the steam turbine is rated at a nominal 19.6 MW.

4.5.4 Greenhouse Gas (GHG) Rulemaking

The use of biomass is generally recognized as "carbon neutral."[2] The U.S. EPA found that because biomass fuels are of biogenic origin, it is assumed that the carbon released during the consumption of biomass is recycled as forests and crops regenerate, causing no net addition of CO_2 to the atmosphere.[3] In addition, the Intergovernmental Panel on Climate Change (IPCC) recently found that bioenergy and the use of dedicated energy crops were key climate change mitigation technologies that should be pursued and "could contribute substantially to the share of renewable energy in the mitigation portfolio."[4]

When biomass is used as a feedstock or a fuel, the carbon involved is on a relatively "short-cycle" — i.e., the carbon dioxide (CO_2) is produced from the oxidation of current or recently living biomass. Since the CO_2 was recently in circulation in the atmosphere, there is no net addition of new CO_2 when it is returned to the atmosphere. For example, when the grass in a person's front yard grows, it removes some CO_2 from the air during photosynthesis and growth. When the yard is mowed, the cut grass decomposes, returning the CO_2 to the atmosphere within days. For other types of biomass, the cycle may take months or even a few years to complete, but the timeframe is still relatively short, and the carbon dioxide released when that biomass is burned or decomposed is not a "new" net addition to the total. The CO_2 balance would be zero. Even when the entire "life cycle" is considered, the use of biomass is still considered carbon neutral.

[2] Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories,* Vol. 3, p. 6.28 (1997); The Climate Registry, *General Reporting Protocol for the Voluntary Reporting Program, Draft for Public Comment* (October 29, 2007), p. 22 (separate reporting for carbon dioxide emissions from biogenic sources); California Environmental Protection Agency, Air Resources Board, *Staff Report: Initial Statement of Reasons for Rulemaking, Proposed Regulation for Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32)* (October 19, 2007), pp. 5, 12 (carbon dioxide emissions from biomass-derived fuels are to be separately identified during reporting; biomass emissions are generally considered "carbon neutral").

[3] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006* (February 22, 2008), Public Review Draft, p. 3-1.

[4] Intergovernmental Panel on Climate Change, *Contribution of Working Group III to the Fourth Assessment Report* (2007), pp. 10, 16.

A complete “life cycle” assessment, which is appropriate for use in considering project’s CO_2 emissions, is where the environmental benefits and impacts are quantified in a cradle-to-grave manner to cover resource consumption and all processes necessary for a power generation system.[5] A life cycle assessment for a biomass facility would include energy and resources used for crop cultivation, preparation, and transportation; construction and operation of the power generation system; emissions; and wastes. Such analyses have indicated that biomass-based power generation systems have neutral or very minimal CO_2 emissions, in part because, as mentioned above, trees and plants absorb CO_2 as they grow and also because CO_2 can accumulate in the soil.[6] When waste biomass is used, the greenhouse gas emissions are further reduced because of the avoided methane generation associated with biomass decomposition that would have occurred had the waste biomass not been used by the power generation system.[7] This results in a net reduction of greenhouse gas emissions.

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[5] Governor’s Action Team on Energy and Climate Change, *Phase 1 Report: Florida’s Energy and Climate Change Action Plan Pursuant to Executive Order 07-127* (November 1, 2007), p. 24 (life cycle assessments are appropriate).

[6] National Renewable Energy Laboratory, *Life Cycle Assessment Comparisons of Electricity from Biomass, Coal, and Natural Gas,* Margaret K. Mann and Pamela L. Spath (November 2002); National Renewable Energy Laboratory, *Life Cycle Assessment of Biomass Gasification Combined-Cycle System,* Margaret K. Mann and Pamela L. Spath (December 1997); Biomass and Energy 25, *Life Cycle Assessment of a Willow Bioenergy Cropping System,* Martin C. Heller, Gregory A. Keoleian, Timothy A. Volk (2003), pp. 147-165.

[7] National Renewable Energy Laboratory, *Life Cycle Assessment Comparisons of Electricity from Biomass, Coal, and Natural Gas,* Margaret K. Mann and Pamela L. Spath (November 2002).

5.0 AIR QUALITY IMPACT ANALYSIS

The Project is a minor source and not subject to Prevention of Significant Deterioration (PSD) review. Air dispersion modeling is generally not required for minor sources. However, an air quality impact analysis is voluntarily provided to demonstrate compliance with the ambient air quality standards. This section contains a summary of the methodologies and results of the air quality impact assessments performed to determine compliance of the proposed project with the national and state ambient air quality standards (AAQS).

5.1 General Modeling Approach

The general modeling approach for the significant impact analysis followed the EPA modeling guidelines for determining compliance with the AAQS. A significant impact analysis was performed for the criteria pollutants: SO_2, NO_X, PM_{10}, and CO to determine whether the new emission sources associated with the Project, given their stack configuration and other modeling inputs, will result in predicted impacts that are in excess of the EPA significant impact levels (SILs). As NAAQS do not exist for VOC and SAM, air impacts for these pollutants are not required.

5.1.1 Site Vicinity

Current policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable Significant Impact Levels (see Table 5-1). If the maximum Project-only impacts are equal to or greater than the SIL in the vicinity of the Project, additional detailed air modeling analyses are required, which are intended to establish cumulative impacts of the project plus existing background sources. This analysis demonstrates compliance with the NAAQS.

5.1.2 PSD Class I Areas

Generally, if a major new facility or major modification is located within 100 km of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impacts of the Project alone at the PSD Class I area.

The Project will be located approximately 75 km from the nearest boundaries of the St. Marks National Wilderness Area (SMNWA) and the Bradwell Bay National Wilderness Area (BBNWA) PSD Class I areas. The SMNWA and BBNWA are the only PSD Class I areas within 100 km of the proposed Project, and a demonstration with the PSD Class I increments will be required for each area. Because the proposed Project is not a major source, demonstrations of compliance with the Federal Land Manager's Air Quality Relative Values (AQRV) are not required.

Per an April 30, 2009 EPA memorandum, the AERMOD model was used in a screening analysis to provide conservative estimates of the maximum concentrations of PM_{10}, SO_2, and NO_2 that would occur at the SMNWA and BBNWA PSD Class I areas. Concentrations are predicted at receptors located 50 km from the proposed site in the direction of the two PSD Class I areas. The maximum predicted concentrations are then compared to the PSD Class I SILs.

If the maximum impacts are significantly above a SIL, additional refinements will need to be conducted using the CALPUFF modeling system to determine if any SILs are exceeded at PSD Class I areas. If the proposed Project's maximum impacts are less than the SILs, cumulative source modeling will not be required.

5.2 Cumulative Source Impact Analysis

5.2.1 NAAQS Analysis

As previously noted, if the Project-only impacts are greater than the SIL, the air modeling analyses must consider other nearby sources and background concentrations, and determine the cumulative impact of these sources for comparison to the NAAQS.

As described in Section 5.9, the proposed Project's annual average and 24-hour average PM_{10} impacts are predicted to be greater than the SIL. Therefore, additional, detailed air modeling analyses must be performed that include the emissions of background sources that are within the modeling domain as generally defined as the extent of the predicted Significant Impact Area plus 50 km. The NAAQS analysis is a cumulative source analysis that evaluates whether the air quality impact from all modeled sources plus a representative monitored concentration will comply with the NAAQS. The background concentration accounts for sources not included in the modeling analysis.

In general, when five years of meteorological data are used in the analysis, the highest annual and the highest, second-highest (HSH) short-term concentrations are compared to the applicable NAAQS. The HSH concentration is calculated each year for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

For determining compliance with the 24-hour NAAQS for PM_{10}, the highest of the sixth-highest concentrations predicted at each receptor over five years of meteorological data (i.e., H6H), instead of the HSH concentration predicted for each year, is used to compare to the applicable 24-hour NAAQS.

5.2.2 PSD Class I Analysis

For each pollutant where maximum predicted impacts exceed the proposed Class I SIL, a cumulative source PSD Class I analysis is required. Since the proposed Project's maximum SO_2, NO_2, and PM_{10} impacts were predicted to be less than the proposed Class I SIL, additional cumulative source analyses to determine compliance with the allowable PSD Class I increments were not required.

5.3 Model Selection

The air modeling analysis was performed using the American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD, Version 09292 to predict concentrations in the vicinity of the proposed Project site location. The modeling analysis is based on predicting impacts within 50 km of the Project. The EPA regulatory default options were used to predict all maximum impacts. These options include:

- Use of elevated terrain algorithms;
- Stack-tip downwash (except for building downwash cases);
- Use of missing data processing routines;
- Use of calm wind processing routines; and
- Use of 4-hour half life for exponential decay of SO_2 for urban sources.

5.4 Meteorological Data

Meteorological data used in the AERMOD model to determine air quality impacts associated with the Project site consisted of a 5-year AERMET meteorological data set for years 2001 through 2005, with surface data from Apalachicola Municipal Airport (AQQ) and twice-daily upper air soundings from Tallahassee Regional Airport. The Apalachicola/Tallahassee data set has been approved by the FDEP for projects in this area. Land use parameters for the AQQ meteorological data record were updated using the procedures outlined in the AERMOD Implementation Guide (2009). Golder used the EPA's AERSURFACE tool (EPA, 2008) to calculate monthly land use values for the AQQ site and incorporated the land use parameters into the meteorological record using AERMOD's meteorological preprocessor program AERMET, Version 06341. A listing of AERMOD features is presented in Table 5-2.

5.5 Emission Inventory

5.5.1 Significant Impact Analysis

A summary of the source location and parameter data for the proposed project is presented in Table 5-3. The CTs/HRSG, cooling towers, gasifier/combustor system, dryer, and baghouses were modeled as point sources; the material handling transfer points were modeled as volume sources; and the storage pile and truck unloading areas were modeled as poly-area and area sources, respectively. A summary of emission rates for the proposed project's sources is presented in Table 5-4.

5.5.2 AAQS Analysis

The maximum impacts for the proposed project are predicted to be greater than the SIL for PM_{10}. As a result, cumulative source impact analysis was required to determine compliance with PM_{10} NAAQS.

The significant impact area (SIA) for PM_{10} was determined based on the maximum distance to which the pollutant had a significant impact. The maximum radius of impact was used as the basis for determining the inventory of background sources to be included in the air impact analysis. The proposed Project's SIA for the 24-hour PM_{10}, and annual average PM_{10} concentrations are predicted to extend out to 1.02 km from the proposed project site, respectively. Based on these results, the SIA was assumed to extend out to 1 Km. EPA modeling guidance require that the background source inventory include source located within and 50 km beyond the predicted SIA.

Facilities located within the SIA were automatically included in the modeling analysis. Facilities located beyond the SIA but within the 51 km (SIA plus 50 km) were considered to be in the screening area. A list of counties located within 51 km of the proposed project site was developed.

The summary of facilities for which PM_{10} emissions were evaluated for inclusion in the PM_{10} NAAQS analysis is shown in Table 5-5. A summary of the detailed source emissions and parameter data included in the PM_{10} NAAQS analysis is presented in Table 5-6.

Premier Chemicals, LLC was a facility located within the modeling area; however, the facility has been closed, thus was not included in the cumulative analysis. In addition, the Lansing Smith Plant of Gulf Power Co. was located beyond the screening area (>100 km), thus was not included in the cumulative analysis.

The UTM locations provided in Tables 5-5, 5-6, 5-8, and 5-9 are based on North American Datum 1983 (NAD83) which were developed by adding 18 m and 210 m, respectively, to the east and north American Datum 1927 (NAD27) coordinates.

5.6 Building Downwash Effects

The proposed HRSG and gasifier/combustor stacks were evaluated for determining compliance with Good Engineering Practice (GEP) regulations and the potential influence of nearby buildings and structures that could cause building downwash. The heights for the HRSG stacks and the gasifier stack are 75 and 100 ft above grade, respectively. For each stack that is below the GEP height, direction-specific building heights and maximum projected widths were determined using the Building Profile Input Program (BPIP, Version 04274), which incorporates the Plume Rise Model Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). The direction-specific building information output by BPIP will be input to the air dispersion model for processing.

A summary of the proposed facility's solid building structures is presented in Table 5-7. The gasifier/combuster area does not have both significant width and depth to be considered as downwash-affecting structures.

5.7 Receptors

Receptors were placed along the Project site's restricted property boundary (i.e., fenceline) and beyond the fenceline according to the following receptor spacing.

- Along the property boundary or fenceline — 50 meters (m);
- Beyond the fenceline to 2 km – 100 m; and
- From 2 km to 4 km – 250 m.

All maximum predicted concentrations were obtained from a receptor grid comprising 50-m resolution on the fence line and 100-m resolution or less beyond the fence line. AERMOD's terrain preprocessing program, AERMAP, Version 09040, was used to process the receptor grid data in all near-field areas, using 7.5-minute U. S. Geological Survey (USGS) Digital Elevation Model (DEM) files.

5.8 Background Concentrations

As previously discussed, representative background concentrations are added to the modeled impacts to determine total (cumulative) ambient air quality impacts. These total impacts are then compared with the appropriate NAAQS to demonstrate the total project impacts will not cause or significantly contribute to a violation of NAAQS. By definition, “background” includes other point sources not included in the modeling analysis (i.e., distant sources or small sources), non-project related fugitive emission sources, and natural background sources. Measured ambient PM_{10} data from the nearest monitors are presented in Table 5-8. The nearest monitor to the proposed project site that measures PM_{10} concentrations is the Cherry Street/Henderson Avenue monitoring station (Site ID 12-005-1004) located in Bay County, Florida. The Cherry Street/Henderson Avenue monitoring station is located approximately 45 km (28 miles) north-northwest of the proposed project site. The highest annual and the highest, second highest 24-hour average PM_{10} concentrations of 20 µg/m^3 and 47 µg/m^3, respectively, were added to the modeled source concentrations to obtain a total concentration for comparison to the NAAQS or State AAQS.

5.9 Modeling Results

5.9.1 PSD Class II Significant Impact Analysis

The modeling results were compared to the PSD Class II significant impact levels (SILs). Since the maximum predicted SO_2, NO_2, and CO impacts due to the proposed Project are less than the SILs, additional modeling analyses are not required for those pollutants. Since the maximum predicted PM_{10} impacts are greater than the SIL, additional cumulative source modeling analyses are required to demonstrate compliance with the AAQS. The Project impacts compared to the SILs are presented in Table 5-9.

5.9.2 PSD Class I Significant Impact Analysis

The Project will be located approximately 75 km from the nearest boundaries of the St. Marks National Wilderness Area (SMNWA) and the Bradwell Bay National Wilderness Area (BBNWA) PSD Class I areas. The SMNWA and BBNWA are the only PSD Class I areas within 100 km of the proposed Project, and a demonstration with the PSD Class I increments will be required for each area. Because the proposed

Project is not a major source, demonstrations of compliance with the Federal Land Manager's Air Quality Relative Values are not required.

Per an April 30, 2009 EPA memorandum, the AERMOD model was used in the screening analysis to provide conservative estimates of the maximum concentrations of PM_{10}, SO_2, and NO_2 that would occur at the SMNWA and BBNWA PSD Class I areas. Concentrations were predicted at receptors located 50 km from the proposed site in the direction of the two PSD Class I areas. The maximum predicted concentrations were compared to the PSD Class I SILs. Since the maximum impacts were below the SILs, cumulative source modeling was not required. A summary of these results is presented in Table 5-10.

5.9.3 PM_{10} AAQS Analysis

A summary of the results of the 24-hour average PM_{10} AAQS modeling analyses is presented in Table 5-11. The maximum annual average and H6H 24-hour total PM_{10} concentrations are predicted to be 26.2 and 97.5 µg/m^3, respectively, which are less than the annual and 24-hour PM_{10} NAAQS of 50 and 150 µg/m^3, respectively.

5.9.4 Conclusions

Based on the detailed air quality modeling analyses, the maximum pollutant concentrations due to the Project are predicted to be less than the PSD Class II Significant Impact Levels for CO, SO_2, and NO_2 for all averaging periods. However, additional detailed modeling analyses were performed for the annual and 24-hour PM_{10} NAAQS. Based on the PSD Class I significant impact analysis, the maximum pollutant concentrations due to the proposed project are predicted to be less than the PSD Class I significant impact levels for all pollutants and that addition detailed modeling are not required at the Class I areas. The results of the cumulative air modeling analyses demonstrate that the Project will comply with all applicable NAAQS, and will not have an adverse effect on human health.

TABLES

Table 2-1. Typical Product Gas Composition[1, 2]

Component	Product Gas Composition (Volume %)
Methane	15.61
Ethylene	5.26
Ethane	0.68
Carbon Monoxide	45.8
Carbon Dioxide	11.03
Hydrogen	20.7
Water Vapor	0.22
Hydrogen Sulfide	0.02
Nitrogen	0.68
Heating Value (Btu/scf) LHV	435.4

[1] Analysis provided by SilvaGas

[2] Gas composition prior to gas clean-up system.

Table 2-2. Startup and Shutdown Emissions Summary

Emission Component	Source	Turnaround Shutdowns, TPY	Emergency Shutdowns, TPY	Start-up, TPY	Controlled Emissions, TPY	**Total Annual Emissions (TPY)**
NOx	Combustion Duct Burner			0.06		
	Gasifier Duct Burner			0.09		
	Char			0.36		
	Wood Combustion			3.56		
	Gasifier Island/Flare	0.025	0.06	0.82		
Total NOx		0.025	0.06	4.83		**4.915**
PM_{10}		0.0025	0.0005	0.51	0.01	**0.523**
PM		0.0025	0.0005	0.51	0.01	**0.523**
CO	Gasifier Island/Flare	0.0011	0.0008			**0.0019**
VOC	Gasifier Island/Flare	0.0003	0.0002			**0.0005**
SO_2	Gasifier Island/Flare	0.009	0.006			**0.015**

* Based upon information from SilvaGas and AP-42 Section 1.1 for Cyclone Furnace, Bituminous

** Based on an estimated 6 planned shutdowns/yr and an estimated 4 emergency shutdowns/yr

TABLE 3-1
NWFREC PROJECT SUMMARY OF POTENTIAL AIR EMISSIONS

Pollutant (TPY)	New CTs (1, 2, & 3)[a]	Gasifier Combustor	Cooling Tower	Material Handling	Auxiliary Boiler	Flare	Dryer	Project Total Emissions
SO_2	11.9	13.1	NA	NA	0.09	0.05	NA	25
PM	61.6	2.5	1.03	12.4	0.03	--[b]	0.10	78
PM_{10}	61.6	2.5	0.73	7.00	0.03	--[b]	0.01	72
NO_x	118.1	42.0	NA	NA	1.47	1.59	NA	163
CO	72.3	14.0	NA	NA	1.24	8.67	NA	96
VOC (as methane)	13.7	7.0	NA	NA	0.08	3.28	NA	24
Fluoride	--[b]	--[b]	NA	NA	NA	--[b]	NA	0
Lead	--[b]	--[b]	NA	NA	NA	--[b]	NA	0
Total HAPs	5.8	5.2	NA	NA	0.03	--[b]	NA	11

[a] Based on emissions at 55°F.

[b] Emissions are negligible

Source: Golder, 2011

Table 3-2. Solar Turbine Emissions per CT/HRSG

Performance @ 55 deg F, 100% Load	
Synthetic Gas Consumption (scf/hr)	1,076,045
Syn Gas H2S Content (%)	0.0005
Fuel Consumption Rate (MMBtu/hr) LHV	468.5
Hours of Operation	8,760
Stack Parameters	
Diameter (ft)	6.5
Height (ft)	75
Temperature (^{o}F)	326
CT Exhaust Flow	
Mass Flow (lb/hr)- provided	409,957
Temperature (°F) - provided	326
Moisture (% Vol.)	7.55
Oxygen (% Vol.)	12.75
Molecular Weight	28.48
Stack Flow Conditions	
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min	
Mass flow (lb/hr)	409,957
Temperature (°F) - provided	326
Molecular weight	28.48
Volume flow (acfm) at 929 F	240,393
Volume flow (acfm) at 326 F	136,008
Velocity (ft/sec)- calculated	68.31
Emissions - one CT	
SO_2 -Basis is syngas sulfur and H2S contents (%)	
Emission Factor (lb/MMBtu)	0.002
(lb/hr)	0.91
(tpy)	4.0
NO_x - (ppm) Solar Turbines Vendor Data - Uncontrolled	115.0
SCR Reduction Rate (%)	87.0
(ppm) Solar Turbines Vendor Data - Controlled	15.0
(lb/hr)	8.99
(tpy)	39.4
CO - (ppm) Solar Turbines Vendor Data - Uncontrolled	50.0
CO Oxidation Reduction Rate (%)	70.0
(ppm) Solar Turbines Vendor Data - Controlled	15.0
(lb/hr)	5.5
(tpy)	24.1
VOC - (ppm) Solar Turbines Vendor Data - Uncontrolled	25.0
(ppm) Solar Turbines Vendor Data - Controlled	25.0
Oxidation Reduction Rate (%)	25.0
(lb/hr UHC)	5.2
%UHC = VOC	20.0
(lb/hr VOC)	1.0
(tpy)	4.6
$PM/PM_{10}/PM_{2.5}$ Solar Turbines Vendor Data	
Based on 0.03 lb/M/BtuM	0.030
LHV (MMBtu/hr)	156.2
Controlled (lb/hr)	4.7
(tpy)	20.5

Source: Solar, See Appendix A.

Table 3-3. Hazardous Air Pollutant Emission Factors and Emissions for the Project Natural Gas and Product Gas-Firing

Parameter		Emission Rate (lb/hr) firing Gas for Operating Conditions of Base Load (1)		Natural Gas Maximum Annual Emissions (TPY) (3)	
Ambient Temperature (^oF):		55° F	CT	55° F 1	55° F 3
HIR (MMBtu/hr):		156		CT/HRSG	CTs/HRSGs
HAPs (Section 112(b) of Clean Air Act)					
1,3-Butadiene		0.000067		0.0003	0.0009
Acetaldehyde		0.0062		0.0274	0.0821
Acrolein		0.0010		0.0044	0.0131
Benzene		0.0019		0.0082	0.0246
Ethylbenzene		0.0050		0.0219	0.0657
Formadehyde		0.403		1.7663	5.2988
Naphthalene		0.00020		0.0009	0.0027
Polycyclic Aromatic Hydrocarbons (PAH)	(3)	0.00034		0.0015	0.0045
Propylene Oxide		0.0045		0.0198	0.0595
Toluene		0.0052		0.0226	0.0677
Xylene		0.010		0.0438	0.1314
Antimony		0.0		0.0000	0.0000
Arsenic		0.0		0.0000	0.0000
Beryllium		0.0		0.0000	0.0000
Cadmium		0.0		0.0000	0.0000
Chromium		0.0		0.0000	0.0000
Lead		0.0		0.0000	0.0000
Manganese		0.0		0.0000	0.0000
Mercury		0.0		0.0000	0.0000
Nickel		0.0		0.0000	0.0000
Selenium		0.0		0.0000	0.0000
HAPs (Total)		0.438		2.88	5.8

(1) Emissions based on the following emission factors and conversion factors for firing natural gas:

Emission Factors		Value	Reference
Sulfuric acid mist		5	%; Conversion of SO_2 to SO_3 in gas turbine
1,3-Butadiene	(a)	0.43	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Acetaldehyde		40	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Acrolein		6.4	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Benzene		12	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Ethylbenzene		32	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Formadehyde		0.091	ppmvd @15% O_2 (see Table 15a)
Naphthalene		1.3	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Polycyclic Aromatic Hydrocarbons (PAH)		2.2	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Propylene Oxide	(a)	29	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Toluene		33	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000. Database
Xylene		64	lb/10^{12} Btu; AP-42,Table 3.1-3. EPA 2000
Antimony		0.00E+00	
Arsenic		0.00E+00	
Beryllium		0.00E+00	
Cadmium		0.00E+00	
Chromium		0.00E+00	
Lead		0.00E+00	
Manganese		0.00E+00	
Mercury		0.00E+00	
Nickel		0.00E+00	
Selenium		0.00E+00	

(a) Based on 1/2 the detection limit; expected emissions are lower.

(2) Annual emissions based on ambient temperature of 55^{o}F firing gas for following hours: 8760

(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

Table 3-4. Gasifier Combustor Emissions

Performance	
Product Gas Produced (MMBtu/hr) LHV	468.5
Quantity of Residual Char (%)	33.0
Heat Input from Residual Char (MMBtu/hr)	155
Char Heating Value (Btu/lb)	14,500
Hours of Operation	8,760
Flow (acfm)	TBD
Emissions	
SO_2 -Basis is feedstock organic sulfur content (%)	0.004
Feedstock Rate (dry TPD)	900
(lb/hr)	3.00
(lb/MMBtu)	0.019
(tpy)	13.1
NO_x - (lb/ton) AP-42, Table 1.2-1	1.80
Char produced (ton/hr)	5.3
(lb/hr)	9.60
(lb/MMBtu)	0.062
(tpy)	42.0
CO - (lb/ton) AP-42, Table 1.2-2	0.6
Char produced (ton/hr)	5.3
(lb/hr)	3.20
(tpy)	14.0
VOC - (lb/ton) AP-42, Table 1.2-6	0.3
Char produced (ton/hr)	5.3
(lb/hr)	1.6
(tpy)	7.0
PM/PM10-(lb/ton) AP-42, Table 1.2-3	71.2
Char produced (ton/hr)	5.3
(lb/hr)	379.6
Cyclone Efficiency (%)	85.0
(lb/hr) controlled	56.9
Baghouse Efficiency (%)	99.0
(lb/hr) controlled	0.57
(lb/MMBtu)	0.004
(tpy)	2.5

Source: Golder, 2011

Table 3-4a. Hazardous Air Pollutant Emission Factors and Emissions for Gasifier Combustor

Performance			
Heat Input from Residual Char (MMBtu/hr)	155	Hours of Operation	8,760
Char Heating Value (Btu/lb)	14,500		
Char produced (ton/hr)	5.3		

HAPs (Section 112(b) of Clean Air Act)	Emission Factor	Emissions	
	(lb/ton)	(lb/hr)	(TPY)
Biphenyl	0.025	0.133	0.584
Naphthalene	0.130	0.693	3.036
Phenanthrene (PAH)	0.007	0.036	0.159
Arsenic	1.9E-04	0.0010	0.004
Antimony	BDL	BDL	BDL
Beryllium	3.1E-04	0.0017	0.007
Cadmium	7.1E-05	0.0004	0.002
Chromium	2.8E-02	0.1493	0.654
Manganese	3.6E-03	0.0192	0.084
Mercury	1.3E-04	0.0007	0.003
Nickel	2.6E-02	0.1386	0.607
Selenium	1.3E-03	0.0069	0.030
HAPs (Total)		**1.2**	**5.2**

Note:
Phenanthrene is a polycyclic aromatic hydrocarbon (PAH).
BDL = Below detection limit

Source:
Emission rates based upon information from AP-42 Section 1.2.
Golder, 2011

TABLE 3-5
SUMMARY OF PM EMISSIONS FROM THE MATERIAL HANDLING OPERATIONS

Operation Scenario	Emission Rate (lb/hr) PM 24-hour Rate	Emission Rate (TPY) PM Annual Rate	Emission Rate (lb/hr) PM10 24-hour Rate	Emission Rate (TPY) PM10 Annual Rate	Emission Rate (lb/hr) PM2.5 24-hour Rate	Emission Rate (TPY) PM2.5 Annual Rate
Fuel Delivery (Paved Road Emissions)	9.02	6.58	0.29	1.28	0.04	0.19
Stack Out Operations	0.23	0.10	0.11	0.05	0.02	0.01
Relcaim Operations	0.016	0.028	0.007	0.013	0.001	0.002
Screen and Hog Mill	0.095	0.067	0.036	0.025	0.0275	0.019
Sand Handling System	0.64	2.82	0.64	2.82	0.64	2.82
Ash Handling System	0.64	2.82	0.64	2.82	0.64	2.82
Total Net Emissions	10.65	12.41	1.73	7.00	1.37	5.85

Source: Golder, 2011

Table 3-6. Feedstock Dryer Emissions

Performance			
None Combustion Drying Through Heat Exchanger			
Dry Wood Throughput		266,450	tons per year
Hours of Operation		8,760	hours per year
Stack Parameters			
Diameter (ft)		TBD	
Height (ft)		TBD	
Temperature (^{o}F)		TBD	
Velocity (ft/sec)		TBD	
Flow (acfm)		TBD	
Emissions			
PM (lb/ton)	AP-42, Table 10.6-1	0.7	lb/ton dry wood
Baghouse Efficiency (%)		99.9	
(lb/hr)		0.022	Controlled
(tpy)		0.10	Controlled
PM10-(lb/ton)	AP-42, Table 10.6-1	0.062	lb/ton dry wood
Baghouse Efficiency (%)		99.9	
(lb/hr)		0.002	Controlled
(tpy)		0.01	Controlled
PM2.5-(lb/ton)	Assumed = PM10	0.062	lb/ton dry wood
Baghouse Efficiency (%)		99.9	
(lb/hr)		0.002	Controlled
(tpy)		0.01	Controlled

Source: Golder, 2011

Table 3-7. Performance, Stack Parameters and Emissions for Auxiliary Boiler

Performance	
Fuel Usage (scf/hr-gas)	60,713
Heat Input (mmBtu/hr-HHV)	62.00
Hours per Year	500
Maximum Fuel Usage (mmscf/yr)	30.36
Stack Parameters	
Diameter (ft)	2.75
Height (ft)	50
Temperature (^{o}F)	296
Velocity (ft/sec)	81
Flow (acfm)	29,000
Emissions	
SO_2 -Basis (grains S/100 scf-gas; %S diesel)	2.00
(lb/hr)	0.35
(tpy)	0.09
NO_x - (lb/mmBtu)	0.095
(lb/hr)	5.89
(tpy)	1.47
CO - (lb/mmBtu)	0.08
(lb/hr)	4.96
(tpy)	1.24
VOC - (lb/mmBtu)	0.005
(lb/hr)	0.31
(tpy)	0.08
PM/PM10 - (lb/10^6 ft^3)	1.90
(lb/hr)	0.12
(tpy)	0.03

Source: Golder, 2011

Table 3-7a. Hazardous Air Pollutant Emission Factors and Emissions for Auxiliary Boiler

Performance			
Fuel Usage (scf/hr-gas) 60,713		Hours of Operation:	500
HAPs (Section 112(b) of Clean Air Act)	Emission Factor ($lb/10^6scf$)	Emissions (lb/hr)	Emissions (TPY)
Formadehyde	7.5E-02	4.6E-03	1.1E-03
Hexane	1.8E+00	1.1E-01	2.7E-02
Naphthalene	6.1E-04	3.7E-05	9.3E-06
Toluene	3.4E-03	2.1E-04	5.2E-05
Arsenic	2.0E-04	1.2E-05	3.0E-06
Beryllium	< 1.2E-05	7.3E-07	1.8E-07
Cadmium	1.1E-03	6.7E-05	1.7E-05
Chromium	1.4E-03	8.5E-05	2.1E-05
Cobalt	8.4E-05	5.1E-06	1.3E-06
Manganese	3.8E-04	2.3E-05	5.8E-06
Mercury	2.6E-04	1.6E-05	3.9E-06
Nickel	2.1E-03	1.3E-04	3.2E-05
Selenium	< 2.4E-05	1.5E-06	3.6E-07
HAPs (Total)		**0.11**	**0.03**

Source:

Emission rates based upon information from AP-42 Section 1.4.

Golder, 2011

Table 3-8. Flare System Emissions

Parameter	Value	Units	Source/Description
Energy Input to Flare	469	MMBtu/hr	
Annual Operation	100	hr/yr	
TOC			
Emission Factor	0.14	lb/MMBtu	AP-42 Table 13.5-1
Emission Rate	66	lb/hr	Emission Rate = Emission Factor * Energy Input
Emission Rate	3	tpy	Emission Rate (tpy) = Emission Rate (lb/hr) * 100 /2000
CO			
Emission Factor	0.37	lb/MMBtu	AP-42 Table 13.5-1
Emission Rate	173	lb/hr	Emission Rate = Emission Factor * Energy Input
Emission Rate	9	tpy	Emission Rate (tpy) = Emission Rate (lb/hr) * 100 /2000
NOx			
Emission Factor	0.07	lb/MMBtu	AP-42 Table 13.5-1
Emission Rate	32	lb/hr	Emission Rate = Emission Factor * Energy Input
Emission Rate	2	tpy	Emission Rate (tpy) = Emission Rate (lb/hr) * 100 /2000
SO2 (Based on Mass Balance)			
Heating Value	435	Btu/scf	Heating Value of Syngas @ 14.7 psia & 60°F
Syngas Flow	1,076,045	scf/hr	468.5 MMBtu * 1,000,000 / 435 btu/scf
H2S in syngas	0.0005	% by vol	
H2S Flow	5.4	scf/hr	1,076,0045 scf/hr * 0.0005 vol %
gas constant	0.0029	cf-atm/mol-K	Constant
H2S Molar Flow	6.43	g-mol/hr	n= (1 atm) * (5.4 scf/hr) / (0.0029 cf-atm/mol-K) / (288.7K)
MW SO2	64	g/g-mol	1 mol of H2S forms 1 mol of SO2
SO2 Mass Flow	412	g/hr	6.43 gmol/hr * 64.1 g/gmol
SO2 Mass Flow	0.9	lb/hr	412 g/hr / 453.59 g/lb
SO2 Mass Flow	0.05	tpy	0.9 lb/hr * 100 / 2000

Soot (PM)

AP-42, TabIe 13.5-1--- fuels with a C:H ratio of less than 0.33 tend not to soot. The average C:H ratio in the syngas is less than 0.33.

Source: Golder, 2011

Table 3-9. Physical, Performance, and Emissions Data for the Mechanical Draft Cooling Towers

Parameter	Steam Turbine Cooling	Compressor Gas Cooling
Physical Data		
Number of Cells	2	3
Deck Dimensions, ft		
Length	96.5	16.4
Width	33.5	12.2
Height(Tower Height)	32.3	17.5
Stack Dimensions		
Height, ft	10.0	5.2
Stack Top Effective Inner Diameter, per cell, ft	21.5	9.0
Effective Diameter, all cells, ft	TBD	TBD
Performance Data (per cell)		
Discharge Velocity, ft/min	1,690	1,799
Circulating Water Flow Rate (CWFR), gal/min	7,050	3,800
Design hot water temperature, °F	113.7	95
Design Air Flow Rate per cell, acfm, (estimated)	1,061,664	114,386
Hours of operation	8,760	8,760
Emission Data		
Drift Rate [a] (DR), percent	0.0020	0.0050
Total Dissolved Solids (TDS) Concentration [b], average	2,000	1,000
Solution Drift [c] (SD), lb/hr	70.2	94.6
PM Drift [d], lb/hr	0.14	0.09
tons/year	0.6	0.4
PM_{10} Drift[e]		
PM_{10} Emissions, lb/hr	0.09	0.08
tons/year	0.4	0.3

[a] Drift rate is the percent of circulating water.

[b] The TDS values assumed are conservative and include cycling.

[c] Includes water and based on circulating water flow rate and drift rate (CWFR x DR x 8.3 lb/gal x 60 min/hr).

[d] PM calculated based on total dissolved solids and solution drift (TDS x SD).

[e] PM_{10} based on Cooling Tower PM_{10} emissions study see Attachment A.

Source: Solar, 2008; Golder, 2011.

Table 5-1 National and State AAQS, and Significant Impact Levels

Pollutant	Averaging Time	AAQS ($\mu g/m^3$) Primary Standard	Secondary Standard	Significant Impact Levels ($\mu g/m^3$) [e]
Particulate Matter[a] ($PM_{2.5}$)	Annual Arithmetic Mean	15	15	NA
	24-Hour Maximum	35	35	NA
Particulate Matter (PM_{10})	Annual Arithmetic Mean	50	50	1
	24-Hour Maximum[b]	150	150	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	1
	24-Hour Maximum[c]	365	NA	5
	3-Hour Maximum	NA	1,300	25
Carbon Monoxide[c]	8-Hour Maximum	10,000	10,000	500
	1-Hour Maximum	40,000	40,000	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	1
Ozone[d]	8-Hour Maximum	147	147	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	NA

Note: Particulate matter ($PM_{2.5}$) = particulate matter with aerodynamic diameter less than or equal to 2.5 micrometers.
Particulate matter (PM_{10}) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

(a) The 3-year average of the weighted annual mean PM2.5 concentrations from single or multiple community-oriented monitors must not exceed 15.0 $\mu g/m^3$. The 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 $\mu g/m^3$ (effective December 17, 2006).
(b) Not to be exceeded more than once per year on average over 3 years.
(c) Not to be exceeded more than once per year.
(d) The 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm (effective 60 days after publication in the Federal Register).
(e) Maximum concentrations are not to be exceeded.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.; 40 CFR 50; 40 CFR 52.21.; COMAR 26.11.04.

TABLE 5-2
MAJOR FEATURES OF THE AERMOD MODEL, VERSION 09292

AERMOD Model Features
• Plume dispersion/growth rates are determined by the profile of vertical and horizontal turbulence, vary with height, and use a continuous growth function. • In a convective atmosphere, uses three separate algorithms to describe plume behavior as it comes in contact with the mixed layer lid; in a stable atmosphere, uses a mechanically mixed layer near the surface. • Polar or Cartesian coordinate systems for receptor locations can be included directly or by an external file reference. • Urban model dispersion is input as a function of city size and population density; sources can also be modeled individually as urban sources. • Stable plume rise: uses Briggs equations with winds and temperature gradients at stack top up to half-way up to plume rise. Convective plume rise: plume superimposed on random convective velocities. • Procedures suggested by Briggs (1974) for evaluating stack-tip downwash. • Has capability of simulating point, volume, area, and multi-sized area sources. • Accounts for the effects of vertical variations in wind and turbulence (Brower et al., 1998). • Uses measured and computed boundary layer parameters and similarity relationships to develop vertical profiles of wind, temperature, and turbulence (Brower et al., 1998). • Concentration estimates for 1-hour to annual average times. • Creates vertical profiles of wind, temperature, and turbulence using all available measurement levels. • Terrain features are depicted by use of a controlling hill elevation and a receptor point elevation. • Modeling domain surface characteristics are determined by selected direction and month/season values of surface roughness length, albedo, and Bowen ratio. • Contains both a mechanical and convective mixed layer height, the latter based on the hourly accumulation of sensible heat flux. • The method of Pasquill (1976) to account for buoyancy-induced dispersion. • A default regulatory option to set various model options and parameters to EPA-recommended values. • Contains procedures for calm-wind and missing data for the processing of short term averages.

Note: AERMOD = The American Meteorological Society and EPA Regulatory Model.
Source: Paine et al., 2011.

TABLE 5-3
SOURCE STACK PARAMETERS

Point Sources	MODEL ID	UTM Coordinates[a] East (m)	UTM Coordinates[a] North (m)	Physical Height (ft)	Physical Height (m)	Physical Diameter (ft)	Physical Diameter (m)	Operating Temperature (°F)	Operating Temperature (K)	Operating Velocity (ft/s)	Operating Velocity (m/s)
CT#1	HRSG1	664,154	3,301,779	75	22.9	6.5	1.98	326	436.5	68.3	20.82
CT#2	HRSG2	664,150	3,301,762	75	22.9	6.5	1.98	326	436.5	68.3	20.82
CT#3	HRSG3	664,163	3,301,777	75	22.9	6.5	1.98	326	436.5	68.3	20.82
Gasifier/Combustor	GASIFIER	664,074	3,301,791	100	30.5	3.8	1.17	300	422.0	60	18.29
Steam Cooling Tower	COOLTOW1	664,199	3,301,755	42.3	12.89	21.5	6.55	114	318.5	28.1	8.56
Steam Cooling Tower	COOLTOW2	664,195	3,301,742	42.3	12.89	21.5	6.55	114	318.5	28.1	8.56
Gasifier Condenser Cooling Tower	GASCOOL1	664,122	3,301,757	22.7	6.92	9.0	2.74	95	308.2	30	9.14
Gasifier Condenser Cooling Tower	GASCOOL2	664,129	3,301,755	22.7	6.92	9.0	2.74	95	308.2	30	9.14
Gasifier Condenser Cooling Tower	GASCOOL3	664,136	3,301,753	22.7	6.92	9.0	2.74	95	308.2	30	9.14
Feed Stock Dryer	DRYER	664,055	3,301,803	50	15.24	0.6	0.18	ambient	ambient	60	18.29
Fuel Silo Baghouse (R6)	FS007	664,056	3,301,805	50	15.24	0.6	0.18	ambient	ambient	60	18.29
Sand System Baghouse	FS009	664,083	3,301,796	50	15.24	0.5	0.15	ambient	ambient	0	0.00
Ash System Baghouse	FS010	664,090	3,301,794	50	15.24	0.5	0.15	ambient	ambient	0	0.00
Baghouse (S6, S7, R3, and Hog Mill)	BAGHS	664,055	3,301,848	50.0	15.2	0.6	0.2	ambient	ambient	60.0	18.3

Volume Sources				Release Height (ft)	Release Height (m)	Side length (ft)	Side length (m)	Initial Sigma y (ft)	Initial Sigma y (m)	Initial Sigma Z (ft)	Initial Sigma Z (m)
Covered Conveyor to Screen (S4) and Screen to Conveyor (S5)	VOL_S4S5	664,058	3,301,850	20	6.1	16.4	5.0	3.8	1.2	4.7	1.4
Reclaim conveyor 1 to reclaim conveyor 2 (R2)	VOL_R2	664,003	3,301,892	32	9.8	10.0	3.0	2.3	0.7	4.7	1.4
Supply conveyor 3 to dryer (R4) and Dryer to conveyor (R5)	VOL_R4R5	664,050	3,301,804	20	6.1	10.0	3.0	2.3	0.7	4.7	1.4
Conveyor to stacker (S8) and stacker to pile (S9)	VOL_S8S9	663,989	3,301,900	20	6.1	10.0	3.0	2.3	0.7	4.7	1.4
Fuel and Ash Trucks	TRUCKSxx	[b]	[b]	7.9	2.4	39.4	12.0	[c]	[c]	7.3	2.2

Area Sources				Release Height (ft)	Release Height (m)
Truck Dump Platforms (S2)	AREA_S2	664,085	3,301,830	0	0
Hopper to covered conveyor transfer point (S3)	AREA_S3	664,098	3,301,820	0	0
Open Pile (S10) and Chain drag to reclaim conveyor (R1)[d]	PILE	663,989	3,301,900	20.0	6.71

[a] UTM Zone 16, North American Datum 83.

[b] Line source comprised of 49 volume sources.

[c] Initial sigma y varies and is based on center-to-center distance between non-overlapping volume sources divided by 2.15.

[d] Pile release height set equal to half the pile height.

TABLE 5-4
SOURCE EMISSIONS

MODEL ID	POINT SOURCES	PM_{10} (lb/hr)	PM_{10} (g/s)	SO_2 (lb/hr)	SO_2 (g/s)	NOx (lb/hr)	NOx (g/s)	CO (lb/hr)	CO (g/s)
HRSG1	CT#1	4.7	0.59	0.91	0.11	8.99	1.13	5.5	0.69
HRSG2	CT#2	4.7	0.59	0.91	0.11	8.99	1.13	5.5	0.69
HRSG3	CT#3	4.7	0.59	0.91	0.11	8.99	1.13	5.5	0.69
GASIFIER	Gasifier/Combustor	0.6	0.07	3.00	0.38	9.60	1.21	3.2	0.40
COOLTOW1	Steam Cooling Tower	0.087	0.011	--	--	--	--	--	--
COOLTOW2	Steam Cooling Tower	0.087	0.011	--	--	--	--	--	--
GASCOOL1	Gasifier Condenser Cooling Tower	0.079	0.010	--	--	--	--	--	--
GASCOOL2	Gasifier Condenser Cooling Tower	0.079	0.010	--	--	--	--	--	--
GASCOOL3	Gasifier Condenser Cooling Tower	0.079	0.010	--	--	--	--	--	--
DRYER	Feed Stock Dryer	0.0020	0.0003	--	--	--	--	--	--
FS007	Fuel Silo Baghouse (R6)	7.2E-05	9.1E-06	--	--	--	--	--	--
FS009	Sand System Baghouse	0.6429	0.0810	--	--	--	--	--	--
FS010	Ash System Baghouse	0.6429	0.0810	--	--	--	--	--	--
BAGHS	Baghouse (S6, S7, R3, and Hog Mill)	0.0362	0.0046	--	--	--	--	--	--
VOL_S4S5	Covered Conveyor to Screen (S4) and Screen to Conveyor (S5)	0.0178	0.0022	--	--	--	--	--	--
VOL_R2	Reclaim conveyor 1 to reclaim conveyor 2 (R2)	0.0015	0.0002	--	--	--	--	--	--
VOL_R4R5	Supply conveyor 3 to dryer (R4) and Dryer to conveyor (R5)	0.0036	0.0005	--	--	--	--	--	--
VOL_S8S9	Conveyor to stacker (S8) and stacker to pile (S9)	0.0178	0.0022	--	--	--	--	--	--
AREA_S2	Truck Dump Platforms (S2)	0.0297	0.0037	--	--	--	--	--	--
AREA_S3	Hopper to covered conveyor transfer point (S3)	0.0089	0.0011	--	--	--	--	--	--
PILE	Open Pile (S10) and Chain drag to reclaim conveyor (R1)	**0.0382**	**0.0048**	--	--	--	--	--	--
TRUCKSxx	**Ash Truck**	**0.0124**	**0.0016**						
	Fuel Truck (S1)	**0.2928**	**0.0369**						

[a] HRSG emissions based on 25°F ambient temperature, after SCR and 90% NO_X reduction.

TABLE 5-5
SUMMARY OF THE PM FACILITIES CONSIDERED FOR INCLUSION IN THE AIR MODELING ANALYSES

AIRS Number	Facility	County	UTM Coordinates (Zone 16) East (km)	UTM Coordinates (Zone 16) North (km)	Relative to BG&E[a] X (km)	Relative to BG&E[a] Y (km)	Relative to BG&E[a] Distance (km)	Relative to BG&E[a] Direction (deg)	Maximum PM Emissions (TPY)	Q, (TPY) Emission Threshold[b,c] (Dist - SID) x 20	Include in Modeling Analysis ?
Modeling Area[d]											
0450001	Premier Chemicals, LLC	Gulf	664.7	3,302.8	0.6	0.9	1.1	34	53.8	1.6	YES
Screening Area[d]											
0450007	Ready Mix USA, LLC	Gulf	662.9	3,299.5	-1.2	-2.4	2.7	206	0.1	33.4	NO
0450002	Arizona Chemical Company, LLC	Gulf	661.9	3,299.6	-2.3	-2.3	3.2	225	5.1	44.1	NO
0050001	Arizona Chemical Company, LLC	Bay	633.1	3,335.4	-31.0	33.5	45.6	317	37.5	892.9	NO
0050009	Smurfit-Stone Container Enterprises, Inc - Panama City Mill	Bay	631.5	3,335.2	-32.6	33.3	46.6	316	491.6	911.2	NO
0050045	Gulf Terminal Corporation	Bay	630.5	3,335.2	-33.6	33.3	47.3	315	1.2	926.4	NO
								Sum =	***530.2***	***812.9***[e]	***NO***
0050031	Bay County Board of County Comissioners	Bay	642.3	3,349.1	-21.8	47.2	52.0	335	59.6	1019.3	NO
7770062	C W Roberts Contracting Inc.		628.1	3,340.3	-36.0	38.4	52.6	317	5.8	1032.6	NO
Beyond Screening Area out to 100 km[d]											
0050014	Gulf Power Company - Lansing Smith Plant	Bay	623.7	3,349.1	-40.4	47.2	62.1	319	2,483.1	1222.2	YES
0770007	North Florida Lumber	Liberty	691.5	3,358.6	27.4	56.7	63.0	26	135.9	1240	NO
0770009	CQ Biopower Producers, LLC - Telogia Power, LLC	Liberty	707.7	3,357.8	43.6	55.8	70.8	38	48.4	1397	NO
0050028	Sage Lumber Company LLC	Bay	608.2	3,356.0	-55.9	54.1	77.7	314	49.1	1534.9	NO
0770010	GA-Pacific Wood Products (Hosford OSB)	Liberty	713.5	3,369.5	49.4	67.6	83.7	36	296.8	1655	NO
0630028	Spanish Trail Lumber Co., LLC - Marianna Sawmill	Jackson	681.5	3,398.8	17.4	96.9	98.4	10	233.3	1949	NO

Note: SID = Significant impact distance for the project, SIA = Significant Impact Area

[a] BG&E UTM East and North Coordinates (km) in Zone 16 are: 664.1 3,301.9

[b] The significant impact distance for the project is estimated to be: 1 km

[c] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is beyond the modeling area and its emission rate is greater than the product of (Distance-SID) x 20.

[d] "Modeling Area" is the area in which the project is predicted to have a significant impact at each mill (approximately 5 km). EPA recommends that all sources within this area be modeled. "Screening Area" is the assumed significant distance of 5 km plus 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area. "Beyond Screening Area" is the distance from 50 km out to 100 km in which large sources are included in the modeling.

[e] Minimum Q for source group. Facilities within a source group are located within 5 km and 3 degrees of one another.

TABLE 5-6
SUMMARY OF PM_{10} SOURCES INCLUDED IN THE AAQS AND PSD CLASS II MODELING ANALYSES

Facility ID	Facility Name / Emission Unit Description	EU ID	Modeling ID Name	UTM Location X (m)	UTM Location Y (m)	Stack Parameters: Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	PM_{10} Emission Rate 24-Hour/Annual (lb/hr)	(g/sec)	Modeled In AAQS
0450001	Premier Chemicals, LLC															
	Multi Hearth Furnace No. 1	006	PCMHF1	664,700	3,302,800	70.0	21.34	6.0	1.83	350.0	449.82	29.5	9.0	3.30	0.42	Yes
	Multi Hearth Furnace no. 2	007	PCMHF2	664,700	3,302,800	70.0	21.34	6.0	1.83	350.0	449.82	29.5	9.0	3.30	0.42	Yes
	Magnesium Oxide Grinding	010	PCMOGRND	664,700	3,302,800	65.0	19.81	2.1	0.64	77.0	298.15	48.1	14.7	5.94	0.75	Yes
	Miscellaneous Activities not subject to Process Weight Table[a]	012	PCMISCAC	664,700	3,302,800	60.0	18.29	1.5	0.46	77.0	298.15	15.0	4.6	2.90	0.37	Yes
0050014	Gulf Power Company - Lansing Smith Plant															
	Boiler No. 1	001	GPCBLR1	625,053	3,349,100	199.0	60.66	18.0	5.49	260.0	399.82	102.7	31.3	194.50	24.51	Yes
	Boiler No. 2	002	GPCBLR2	625,053	3,349,100	199.0	60.66	18.0	5.49	260.0	399.82	102.7	31.3	224.60	28.30	Yes
	Combustion Turbines A & B	003	GPCCTAB	623,740	3,349,110	33.0	10.06	13.7	4.18	1,200.0	922.04	120.9	36.9	20.68	2.606	Yes
	Unit 4	004	GPCU4	625,237	3,349,628	121.0	36.88	16.8	5.12	186.0	358.71	73.8	22.5	21.50	2.71	Yes
	Unit 5	005	GPCU5	625,234	3,349,666	121.0	36.88	16.8	5.12	186.0	358.71	73.8	22.5	21.50	2.71	Yes
	Salt Water Cooling Tower	006	GPCSWCT	623,740	3,349,110	57.0	17.37	33.0	10.06	98.0	309.82	259.2	79.0	18.20	2.29	Yes
	Material Handling of Coal and Ash[b]	007	GPCMH	623,740	3,349,110	15.0	4.57	30.0	9.14	77.0	298.15	15.0	4.6	22.99	2.90	Yes
	Fugitive Source - On-Site Vehicles[b]	008	GPCVEH	623,740	3,349,110	15.0	4.57	30.0	9.14	68.0	293.15	15.0	4.6	22.99	2.90	Yes
	General Purpose Internal Combustion Engines[b]	009	GPCICE	623,740	3,349,110	20.0	6.10	30.0	9.14	400.0	477.59	15.0	4.6	0.01	0.002	Yes

[a] A velocity of 15.0 ft/s was assumed due to limited information.

[b] Fugitive emissions sources were modeled as point sources for background source data. A height of 15 ft, diameter of 30 ft, velocity of 15 ft/s and temperature of 68ºF (ambient) were assumed unless other information was available.

TABLE 5-7
SOLID STRUCTURE DIMENSIONS

STRUCTURE TYPE (# included)	Height		Length		Width	
	(ft)	(m)	(ft)	(m)	(ft)	(m)
CTs (3)	50.0	15.2	13.6	4.2	6.7	2.0
Cooling Towers (2)	32.3	9.8	88.5	27.0	34.8	10.6
Gas Compressor Cooling Towers (3)	17.5	5.3	17.2	5.2	13.0	4.0

Source: Golder, 2011

TABLE 5-8

NON-MODELED BACKGROUND CONCENTRATIONS USED FOR THE MODELING ANALYSIS

Pollutant	Site Name	Year	Site ID	County	City	Annual Mean ($\mu g/m^3$)	24-Hour Maximum ($\mu g/m^3$) 1st	24-Hour Maximum ($\mu g/m^3$) 2nd
PM_{10}	Cherry St And Henderson Avenue	2007	12-005-1004	Bay	Panama City	22.0	163.0	83.0
	Cherry St And Henderson Avenue	2008	12-005-1004	Bay	Panama City	20.0	53.0	47.0

Boxed values were selected as non-modeled background concentrations for the NAAQS.

TABLE 5-9
SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR PROPOSED PROJECT COMPARED TO EPA CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Maximum Concentration ($\mu g/m^3$)[a]	EPA Class II Significant Impact Levels ($\mu g/m^3$)
SO_2	Annual	0.2	1
	24-Hour	3.0	5
	3-Hour	4.3	25
PM_{10}	Annual	3.8	1
	24-Hour	20.8	5
NO_2[b]	Annual	0.82	1
CO	8-Hour	11.3	500
	1-Hour	17.4	2,000

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2001 to 2005 consisting of surface and upper air data from the National Weather Service stations at Apalachicola and Tallahassee Municipal Airports, respectively.

[b] NO_x to NO_2 conversion factor of 0.75 applied to modeled NOx impacts based on EPA Modeling Guidelines.

TABLE 5-10
SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR PROPOSED PROJECT COMPARED TO EPA CLASS I SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Maximum Concentration ($\mu g/m^3$)[a]	EPA Class I Significant Impact Levels ($\mu g/m^3$)
St. Marks Wilderness Area			
SO_2	Annual	0.030	0.1
	24-Hour	0.001	0.2
	3-Hour	0.164	1
PM_{10}	Annual	0.003	0.2
	24-Hour	0.09	0.3
NO_2[b]	Annual	0.005	0.1
Bradwell Bay Wilderness			
SO_2	Annual	0.001	0.1
	24-Hour	0.036	0.2
	3-Hour	0.161	1
PM_{10}	Annual	0.003	0.2
	24-Hour	0.104	0.3
NO_2[b]	Annual	0.005	0.1

[a] Concentrations at St. Marks Wilderness Area and Bradwell Bay Wilderness are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2001 to 2005 consisting of surface and upper air data from the National Weather Service stations at Apalachicola and Tallahassee Municipal Airports, respectively.

[b] NO_x to NO_2 conversion factor of 0.75 applied to modeled NOx impacts based on EPA Modeling Guidelines.

TABLE 5-11
MAXIMUM PREDICTED IMPACTS FOR ALL SOURCES COMPARED TO THE NAAQS

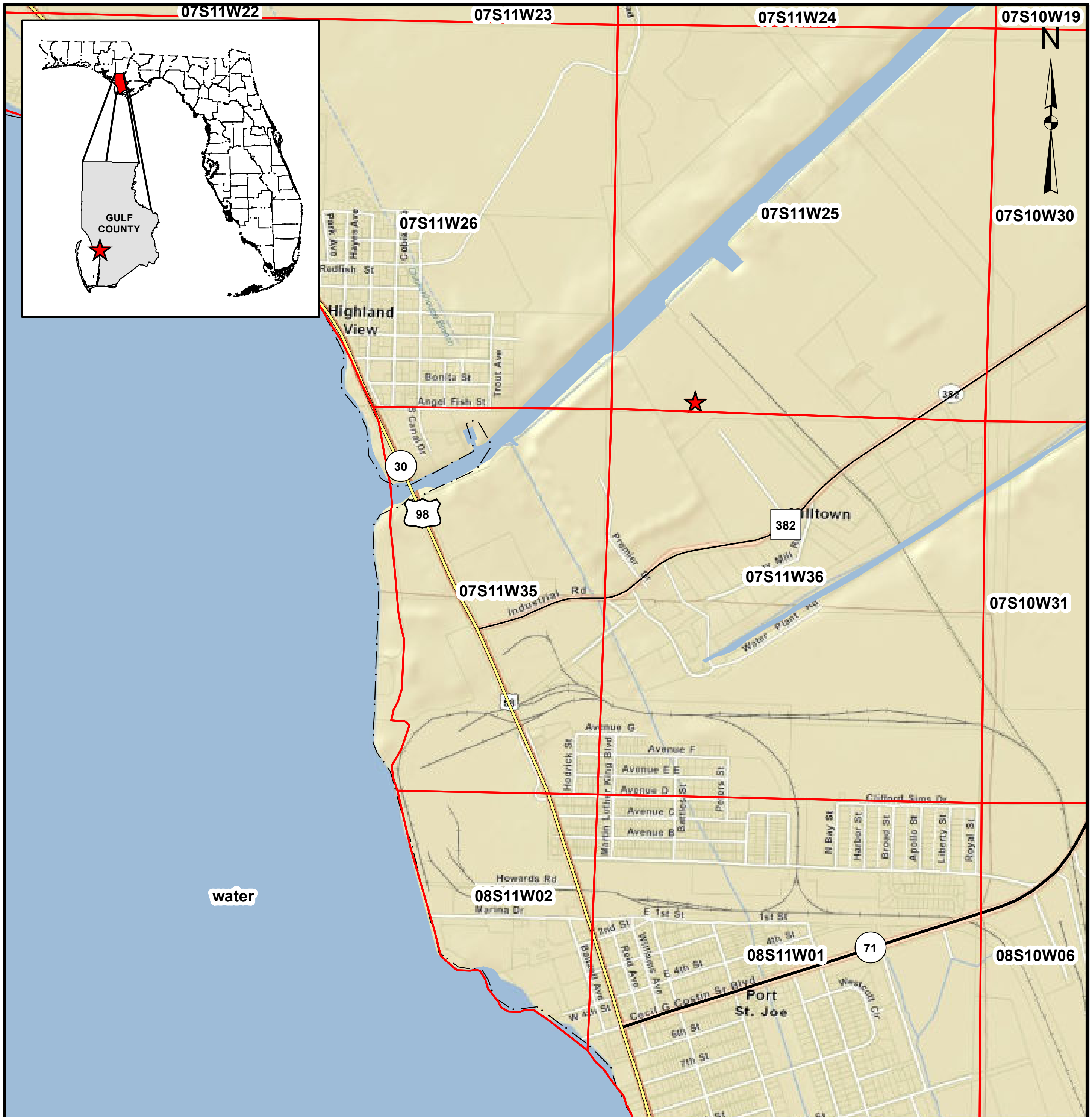
Averaging Time and Rank	Concentration ($\mu g/m^3$)[a] Total (a+b)	Modeled Sources (a)	Background[b] (b)	UTM Coordinates East (m)	North (m)	Time Period (YYMMDDHH)	AAQS ($\mu g/m^3$)
PM_{10}							
Annual	26.2	4.2	22.0	663,994	3,301,729	01123124	50
	26.0	4.0	22.0	663,994	3,301,729	02123124	
	25.9	3.9	22.0	663,994	3,301,729	03123124	
	25.9	3.9	22.0	663,994	3,301,729	04123124	
	25.9	3.9	22.0	663,994	3,301,729	05123124	
24-Hour, H6H	97.5	14.5	83.0	664000	3301700	05030324	150

Note: YYMMDDHH = Year, Month, Day, Hour Ending
HSH = Highest, second-highest predicted concentration for any year
H6H = Highest, sixth-highest predicted concentration in 5 years

[a] Concentrations are predicted using AERMOD with 5 years of meteorological data for 2001 to 2005 consisting of surface and upper air soundings from the weather stations at Apalachicola and Tallahassee, FL, respectively.

[b] Background concentrations are summarized in Table 5-8.

FIGURES



LEGEND

- ★ Approximate Project Location
- Interstate
- Toll Road
- US Road
- State Road
- County Road
- Township-Range -Section
- County Boundary

REGIONAL MAP

REFERENCES

1. Approximate Project Area: Golder Associates Inc., 2011
2. Roads: Florida Department of Transportation, 2010 & Hillsborough County, 2010
3. Township-Range-Section: Florida Resources & Environmental Analysis Center, 2003
4. County Boundaries: Florida Geographic Data Library, 2008
5. Base Map: DeLorme, 2009

2,000 0 2,000 Feet

REV.	DATE	DES	REVISION DESCRIPTION	GIS	CHK	RVW

PROJECT

NWFREC, LLC

TITLE

SITE LOCATION

Golder Associates
Tampa, Florida

PROJECT No. 103-89656		
DESIGN	JG	01/26/2011
GIS	JG	01/26/2011
CHECK	PP	01/26/2011
REVIEW	SO	01/26/2011

FILE No. 103-89656A001

SCALE: AS SHOWN REV. 0

FIGURE 2-1

F:\PROJECTS\2010 PROJ\103-89656 BEHA - Site Location\GIS\MXD\103-89656A001 Site Location.mxd

NOTES:

1. REFER TO SHEET 18.01 FOR NOTES AND LEGENDS.
2. DESIGN OF PROPOSED POWER PLANT COMPONENTS (INCLUDING FEEDSTOCK UNLOADING AREA, CONVEYORS, STACK/RECLAIM AREA, SUBSTATION, ETC.) AND BUILDINGS PROVIDED BY OTHERS AND ARE NOT ASSOCIATED WITH THESE CONSTRUCTION DRAWINGS.
3. THESE CONSTRUCTION DRAWINGS DO NOT INCLUDE SITE LIGHTING OR LANDSCAPE DESIGN.

NOT FOR CONSTRUCTION ISSUED FOR PERMITTING NORTHWEST FLORIDA RENEWABLE ENERGY CENTER 01-05-2011

Date	Description	No.
	Revisions	

PROGRESS PRINT
2011-01-05

JOSEPH J. YANNUCCI, JR., P.E.
PROFESSIONAL ENGINEER FL LIC. No. 65969

LANGAN
ENGINEERING & ENVIRONMENTAL SERVICES
325 John Knox Road
Suite L-500
Tallahassee, FL 32303
P: 850.523.3900 F: 850.523.3950
www.langan.com
NEW JERSEY PENNSYLVANIA NEW YORK CONNECTICUT FLORIDA NEVADA
FL Certificate of Authorization No: 00006601

Project
NORTHWEST FLORIDA RENEWABLE ENERGY CENTER
CITY OF PORT ST. JOE
GULF COUNTY FLORIDA

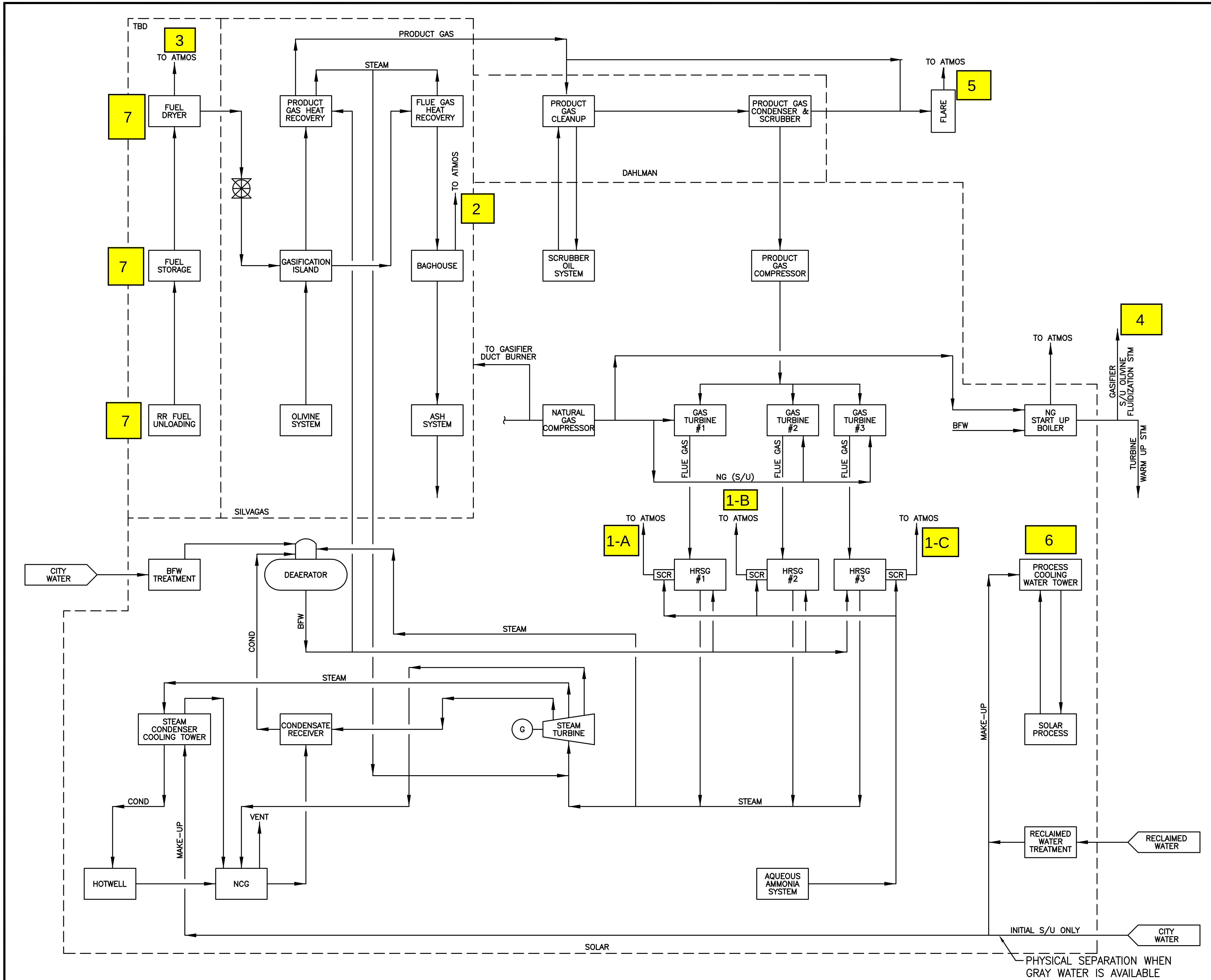
Drawing Title
OVERALL SITE PLAN
FIGURE 2-2

Project No.	320011101
Date	25 AUGUST 2009
Scale	1" = 120'
Drn. By	TLT
Chkd. By	JJY

Drawing No. 20.00

03 Of 18

Filename: \\Langan.com\data\EP\data1\320011101\Cadd Data - 320011101\Dwg\320011101 2000.dwg Date: 1/5/2011 Time: 11:33 User: mcarr Style Table: Langan.stb Layout: D Size Sheet (Bottom)



REV	DATE	DRWN BY	CHKD BY	APVD BY	DESCRIPTION
B	01/13/11				ADDED 3RD GAS TURBINE
A	10/19/09				FOR INFORMATION

REVISIONS

Ford, Bacon & Davis
A Limited Liability Company

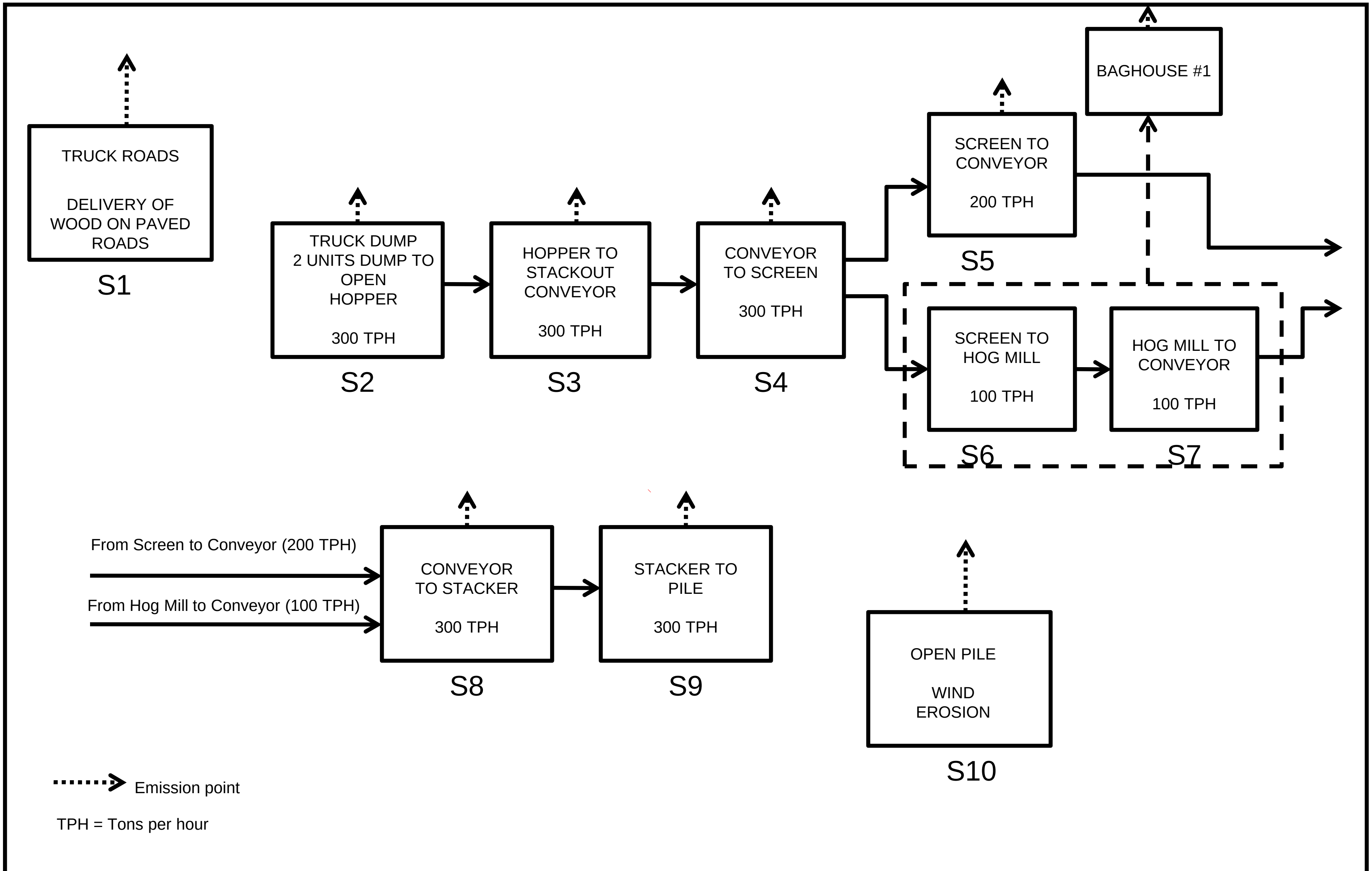
FIGURE 2-3

NORTHWEST FLORIDA RENEWABLE ENERGY CENTER, LLC

FB&D JOB NUMBER: Y7211
SCALE: NO SCALE
DATE: 03/03/2008
DRAWN BY: S. MURPHREE

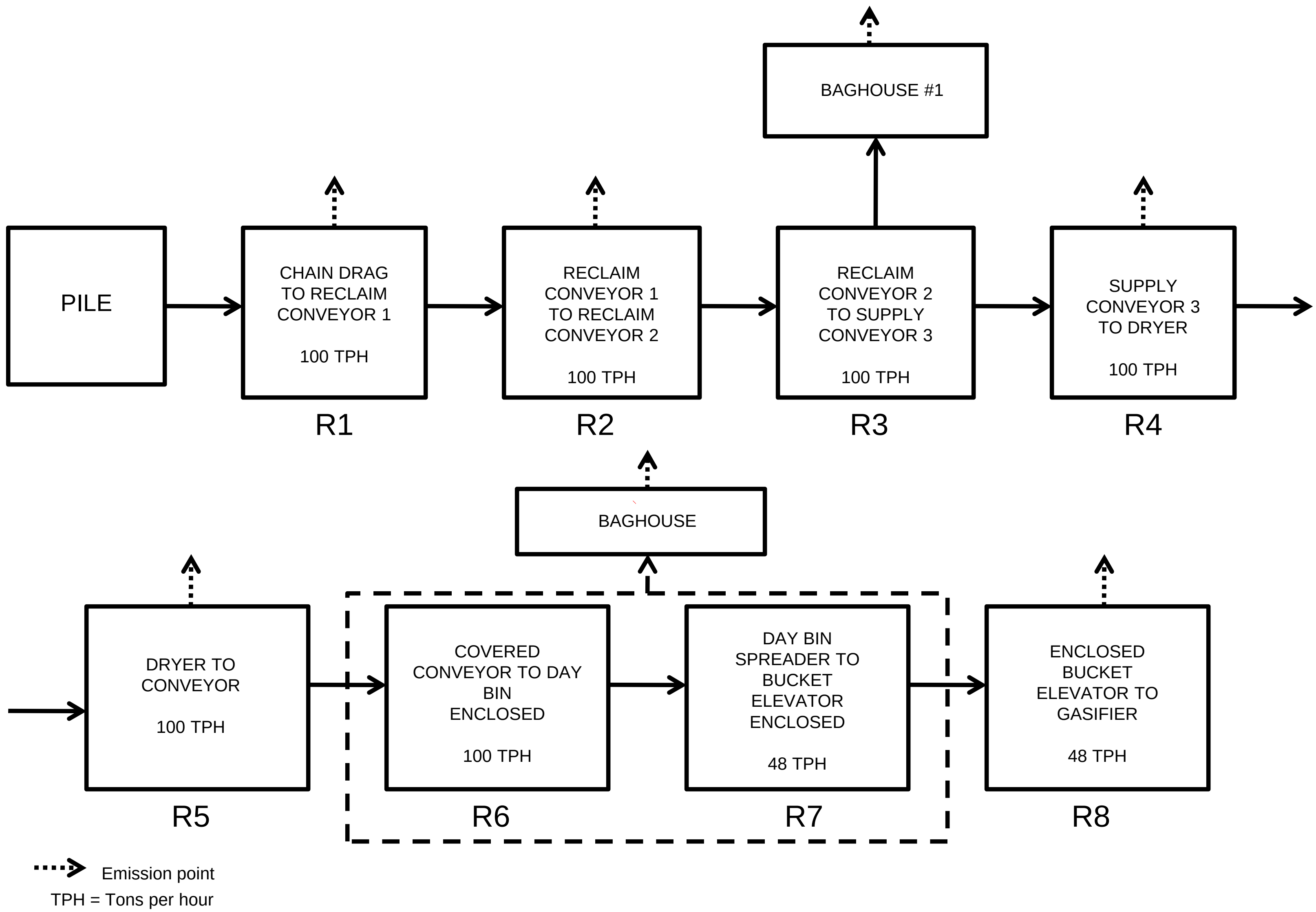
PFD-ALL AREAS-01

REV. B



CLIENT/PROJECT	TAMPA, FLORIDA	TITLE
NWFREC, LLC	Golder Associates	**Figure 2-4 Material Handling Emission Points (Stack - out)**

DRAWN	CHECKED	REVIEWED	DATE 1/26/2011	NOT TO SCALE	FILE NO.	Job No. 103-89656	DWG NO.	SUBTITLE	REV. NO.



CLIENT/PROJECT		TITLE
NWFREC, LLC	Golder Associates, TAMPA, FLORIDA	**Figure 2-5 Material Handling Emission Points (Reclaim)**

DRAWN	CHECKED	REVIEWED	DATE 1/26/2011	NOT TO SCALE	FILE NO.	Job No. 103-89656	DWG NO.	SUBTITLE	REV. NO.

APPLICATION FORMS

FDEP Form No. 62-210.900(1), Application for Air Permit — Long Form.

Department of
Environmental Protection
Division of Air Resource Management
APPLICATION FOR AIR PERMIT - LONG FORM
I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Biomass Energy Holdings, LLC**	
2. Site Name: **Northwest Florida Renewable Energy Center (NWFREC), LLC.**	
3. Facility Identification Number: **TBD**	
4. Facility Location...: **521 Premier Drive** Street Address or Other Locator: **P.O. Box 129** City: **Port St. Joe** County: **Gulf** Zip Code: **32457**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: **Kenn Davis, Manager**
2. Application Contact Mailing Address... Organization/Firm: **Biomass Energy Holdings, LLC** Street Address: **P.O. Box 366** City: **Clinton** State: **IN** Zip Code: **47842**
3. Application Contact Telephone Numbers... Telephone: (**765**) **832-8526** ext.**2526** Fax: (**765**) **832-1860**
4. Application Contact Email Address: **kdavis@bioeh.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.
☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.
☐ Title V air operation permit revision.
☐ Title V air operation permit renewal.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.
☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Application is for the construction of a nominal 66.7 MW gross (55.4 MW net) combined cycle unit consisting of three combustion turbines (CTs) and associated heat recovery steam generators (HRSGs), a steam turbine, a material handling system, a biomass gasification system, a dryer, an auxiliary boiler, an emergency flare system, and two mechanical draft cooling towers.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	CT 1A, 1B, and 1C	AC1A	5,000
002	Gasifier Combustor	AC1A	2,000
003	Dryer	AC1A	250
004	Auxiliary Boiler	AC1A	250
005	Emergency Flares	AC1A	1,000
006	Cooling Towers	AC1A	250
007	Material Handling	AC1A	1,000

Application Processing Fee

Check one: ☒ Attached - Amount: $ 9,750 ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **Glenn Farris, VP Business Development**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Biomass Energy Holdings, LLC** Street Address: **3500 Parkway Lane, Suite 400** City: **Atlanta** State: **GA** Zip Code: **30092**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **770-662-0256** ext. Fax:
4.	Owner/Authorized Representative Email Address: **gfarris@bioeh.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature Jan 31, 2018 Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source, CAIR source, or Hg Budget source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5. Application Responsible Official Email Address:
. Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* ____________________ ______________ Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott H. Osbourn**
   Registration Number: **57557**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **5100 West Lemon Street, Suite 208**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287-1717** ext.**53304** Fax: **(813) 287-1716**
4. Professional Engineer Email Address: **sosbourn@golder.com**
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here **X** *, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.*

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here , if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature

Date 1/31/11

(seal)

SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
** Board of Professional Engineers Certificate of Authorization #00001670

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **16** East (km) **672,212** North (km) **3,302,079**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **29/50/14 N** Longitude (DD/MM/SS) **85/18/03 W**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment : **The project consists of the construction of a nominal 66.7 MW gross (55.4 MW net) combined cycle unit consisting of three combustion turbines (CTs) and associated heat recovery steam generators (HRSGs), a steam turbine, a material handling system, a biomass gasification system, a dryer, an auxiliary boiler, an emergency flare system, and two mechanical draft cooling towers.**			

Facility Contact

1. Facility Contact Name: **Kenn Davis, Manager**
2. Facility Contact Mailing Address... Organization/Firm: **Biomass Energy Holdings, LLC** Street Address: **P.O. Box 366** City: **Clinton** State: **IN** Zip Code: **47842**
3. Facility Contact Telephone Numbers: Telephone: (**765**) **832-8526** ext.**2526** Fax: (**765**) **832-1860**
4. Facility Contact Email Address: **kdavis@bioeh.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☐ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Less than major source threshold (250 TPY) for PSD applicability** **CT and HRSG – NSPS Subpart KKKK**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	**A**	**N**
PM_{10}	**A**	**N**
SO_2	**A**	**N**
NO_x	**A**	**N**
CO	**A**	**N**
VOC	**A**	**N**

FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap
7. Facility-Wide or Multi-Unit Emissions Cap Comment:					

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date:____
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date:____
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date:____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **See Report** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **See Report**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **See Report**
4.	List of Exempt Emissions Units: ☒ Attached, Document ID: **See Report** ☐ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☒ Attached, Document ID: **See Report** ☐ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☒ Attached, Document ID: **See Report** ☐ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: **See Report** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: **See Report** ☐ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: **See Report** ☐ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for FESOP Applications

1.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:_____ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:_____ ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:_____ ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:_____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:_____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:_____ ☐ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:_____ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   ☒ Attached, Document ID: **NWF-FI-C1** ☐ Previously Submitted, Date:__________
   ☐ Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☐ Not Applicable

   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☐ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable (not a CAIR source)

Additional Requirements Comment

A certificate of representation (EPA Form 7610-1) has been included as attachment NWF-FI-C2.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Three identical Solar Model T-130 CTs with HRSGs. Units designated as 1A, 1B an 1C.

3. Emissions Unit Identification Number: **1A, 1B, and 1C**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**1/2012**	**1/2013**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☒ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **(See comment below)** MW

11. Emissions Unit Comment:
The power block will have a nominal capacity of 66.7 MW (gross) and 55.4 MW (net) consisting of three CT/HRSG trains. The CTs will be rated at 47.1 MW (15.7 per CT) and the steam turbine is rated at 19.6 MW. Emission unit information is presented for one CT/HRSG. Any differences in the information contained in the form and the emission calculations contained in the Report are due to round-off.

Emissions Unit Control Equipment/Method: Control **1** of **3**

1. Control Equipment/Method Description: **- Selective Catalytic Reduction (SCR)**	
2. Control Device or Method Code: **25**	

Emissions Unit Control Equipment/Method: Control **2** of **3**

1. Control Equipment/Method Description: **- Clean Fuels (Product Gas/Natural Gas)**	
2. Control Device or Method Code: **28**	

Emissions Unit Control Equipment/Method: Control **3** of **3**

1. Control Equipment/Method Description: **- Good Combustion Practices**	
2. Control Device or Method Code: **65**	

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **468.5** million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rate is for each CT firing product gas (natural gas and/or biofuel, ULSD fuel oil used for startups), (LHV), 55°F.**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **See Report, ID Nos. 1A/1B/1C**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through the HRSG stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **75**feet	7. Exit Diameter: **6.5**feet
8. Exit Temperature: **326**°F	9. Actual Volumetric Flow Rate: **TBD** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Emission point characteristics for baseload and product gas-firing at 55 degrees F.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Product Gas; Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet product gas burned**	
4. Maximum Hourly Rate: **0.36**	5. Maximum Annual Rate: **3,145.5**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.002**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **435**
10. Segment Comment: **Max hourly fuel usage based on baseload at 55 degrees F, 156.2 MMBtu/hr per CT, and fuel LHV of 435 Btu/scf.** **Annual fuel usage based on 8,760 hours per year (hr/yr) operation at baseload and 55 degrees F. See Section 2.2.2 in Report for fuel usage during different operating conditions.**		

Segment Description and Rate: Segment **2** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Natural Gas; Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet natural gas burned**	
4. Maximum Hourly Rate: **0.16**	5. Maximum Annual Rate: **119.5**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **980**
10. Segment Comment: **Natural gas is only used as a startup fuel. Max hourly fuel usage based on baseload at 55 degrees F, 156.2 MMBtu/hr per CT, and fuel LHV of 980 Btu/scf.** **Annual fuel usage based on 750 hours per year (hr/yr) operation at baseload and 55 degrees F. See Section 2.2.2 in Report for fuel usage during different operating conditions.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
PM_{10}			EL
SO_2			EL
NO_x	25, 28, 65	25, 28, 65	EL
CO	109	109	EL
VOC	109	109	EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated, Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.7** lb/hour **20.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.7 lb/hour** Reference: **Solar, 2011; Golder, 2011**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Emissions are for one CT/HRSG and represent product gas (worst-case). Specifically, for each hour on natural gas or biofuel/ULSD fuel oil (startup), emissions will be less than represented for product gas. See Report, Table 3-2.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% Opacity**	4. Equivalent Allowable Emissions: **4.7** lb/hour **20.5**tons/year
5. Method of Compliance: **Initial VE test using EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% Opacity**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Initial VE test using EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated, Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.7** lb/hour **20.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.7 lb/hour** Reference: **Solar, 2011; Golder, 2011.**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Emissions are for one CT/HRSG and represent product gas (worst-case). Specifically, for each hour on natural gas or biofuel/ULSD fuel oil (startup), emissions will be less than represented for product gas. See Report, Table 3-2.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **4.7** lb/hour **20.5** tons/year
5. Method of Compliance: **Initial VE test using EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Initial VE test using EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated, Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.91** lb/hour **4.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.002 lb/MMBtu** Reference: **Solar, 2011; Golder, 2011.**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emissions = 0.91 lb/hr (55°F, Base mode).
Annual Emissions = (0.91 lb/hr x 8,760 hr/yr) x ton/2,000 lb = 4.0 TPY.
Emissions are for one CT/HRSG and represent product gas (worst-case). Specifically, for each hour on natural gas or biofuel/ULSD fuel oil (startup), emissions will be less than represented for product gas. See Report, Table 3-2.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.002 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.91**lb/hour **4.0**tons/year
5. Method of Compliance: **Fuel sampling. Complies with NSPS, Subpart KKKK limit of 0.60 lb/MMBtu.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated, Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **8.99** lb/hour **39.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **15.0 ppmvd controlled - solar turbine vendor data** Reference: **Solar, 2011; Golder, 2011.**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emissions = 8.99 lb/hr (55°F, Base mode)..
Annual Emissions = (8.99 lb/hr x 8,760 hr/yr) x ton/2,000 lb = 39.4 TPY.
Emissions are for one CT/HRSG and represent product gas (worst-case). Specifically, for each hour on natural gas or biofuel/ULSD fuel oil (startup), emissions will be less than represented for product gas. See Report, Table 3-2.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **15.0 ppmvd @15% O2**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **EPA Method 20 and 7E; annual test.**	
6. Allowable Emissions Comment (Description of Operating Method): **NSPS, Subpart KKKK allowable limit.**	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated, Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **5.5** lb/hour **24.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **15.0 ppmvd (controlled) Solar turbine vendor data** Reference: **Solar, 2011; Golder, 2011**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly emissions = 5.5 lb/hr (55°F, Base mode).** **Annual Emissions = (5.5 lb/hr x 8,760 hr/yr) x ton/2,000 lb = 24.1 TPY.** **Emissions are for one CT/HRSG and represent product gas (worst-case). Specifically, for each hour on natural gas or biofuel/ULSD fuel oil (startup), emissions will be less than represented for product gas. See Report, Table 3-2.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: **5.5** lb/hour **24.1** tons/year
5. Method of Compliance: **Annual test using EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated, Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.0** lb/hour **4.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **25.0 ppmvd UHC (controlled) Solar data - VOC 20% of UHC** Reference: **Solar, 2011; Golder, 2011.**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Annual Emissions = (5.2 lb/hr x 0.20 x 8,760 hr/yr) x ton/2,000 lb = 4.6 TPY.** **Emissions are for one CT/HRSG and represent product gas (worst-case). Specifically, for each hour on natural gas or biofuel/ULSD fuel oil (startup), emissions will be less than represented for product gas. See Report, Table 3-2.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Per Solar document (PIL 168, Rev 3) VOC emissions are 10-20% of the UHC emission rate. This estimate is based on a ratio of total non-methane hydrocarbons to total organic compounds. The use of 20% provides a conservative estimate of VOC emissions.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: **1.0** lb/hour **4.6** tons/year
5. Method of Compliance: **EPA Methods 18, 25, or 25A at base load. Initial test only.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **2**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20**% Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **FDEP Rule 62-296.320(4)(b)1, F.A.C. requires 20% opacity. Excess emissions provided by Rule 62-210.700.**	

Visible Emissions Limitation: Visible Emissions Limitation **2** of **2**

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunction.**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **3**

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **not yet identified** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR, Part 75. NO_x monitoring includes diluent monitor (O_2 or CO_2).**	

Continuous Monitoring System: Continuous Monitor **2** of **3**

1. Parameter Code: **EM**	2. Pollutant(s): **O2 or CO2**
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **not yet identified** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitor required for diluent.**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **3** of **3**

1. Parameter Code: **CEMS**	2. Pollutant(s): **CO**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **not yet identified** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
8. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
8. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute:
   ☒ Attached, Document ID: **See Report** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☒ Attached, Document ID: **See Report** ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: **See Report** ☐ Not Applicable	
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See Report** ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☐ Attached, Document ID: _____ ☐ Not Applicable	
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☐ Not Applicable	
3. Alternative Methods of Operation: ☐ Attached, Document ID: _____ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☐ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Gasification System Combustor

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**1/2012**	**1/2013**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

See Report, Section 3.2 for description. A process schematic is provided in Figure 2-6.

Emissions Unit Control Equipment/Method: Control **1** of **1**

1.	Control Equipment/Method Description: **Fabric Filters and Cyclones**
2.	Control Device or Method Code: **017 and 021**

Emissions Unit Control Equipment/Method: Control ___ of ___

1.	Control Equipment/Method Description:
2.	Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1.	Control Equipment/Method Description:
2.	Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1.	Control Equipment/Method Description:
2.	Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **155** million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **See Report**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **100**feet	7. Exit Diameter: **3.8**feet
8. Exit Temperature: **300**°F	9. Actual Volumetric Flow Rate: **TBD** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Table 3-4 presents emission point information.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

<u>Segment Description and Rate:</u> Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **Char Production**		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate: **5.3 TPH**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,055**
10. Segment Comment: **Maximum annual rate based on 8,760 hr/yr operation. See Report, Section 3.2 and Table 3-4.**		

<u>Segment Description and Rate:</u> Segment _____ of _____

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			NS
PM/PM10			NS
NOx			NS
SO2			NS
VOC			NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.2** lb/hour **14.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.6 lb/ton** Reference: **AP-42, Table 1.2-2**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Table 3-4.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions **Allowable Emissions 1 of 1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **9.6** lb/hour **42.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.8 lb/ton** Reference: **AP-42, Table 1.2-1**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Table 3-4.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.0** lb/hour **13.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Table 3-4**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Table 3-4.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.6** lb/hour **2.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **71.2 lb/ton** Reference: **AP-42, Table 1.2-3**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Table 3-4.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.6** lb/hour **7.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.3 lb/ton** Reference: **AP-42, Table 1.2-6**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Table 3-4.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **1**

1. Visible Emissions Subtype: **VE05**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **5 %** Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Excess emissions provided by Rule 62-210.700.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **1**

1. Parameter Code: **COM**	2. Pollutant(s): **VE**
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: **TBD** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date ____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date ____

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date ____

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☒ Attached, Document ID: **See Report** ☐ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☒ Attached, Document ID: **See Report** ☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: **See Report** ☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See Report** ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☐ Attached, Document ID: _____ ☐ Not Applicable
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☐ Not Applicable
3. Alternative Methods of Operation: ☐ Attached, Document ID: _____ ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☒ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Feedstock Dryer

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**1/2012**	**1/2013**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

The feedstock dryer will use waste heat (i.e., heat exchange); no combustion is involved.

Emissions Unit Control Equipment/Method: Control 1 of 2

1.	Control Equipment/Method Description: **Baghouse controls**
2.	Control Device or Method Code: **018**

Emissions Unit Control Equipment/Method: Control __ of __

1.	Control Equipment/Method Description:
2.	Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1.	Control Equipment/Method Description:
2.	Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1.	Control Equipment/Method Description:
2.	Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **1,285 wet tons per day (WTPD)**		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: million Btu/hr		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **The throughput rate of 1,285 WTPD assumes an average feedstock moisture of ~30%. The feedstock leaves the dryer at ~ 23% moisture and 900 dry tons per day (DTPD).**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **See Report**		2. Emission Point Type Code:
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhaust gas exits at dryer baghouse. See Figure 2-4 (Material handling Process Schematic).**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **50**feet	7. Exit Diameter: **0.6**feet
8. Exit Temperature: **25** °F	9. Actual Volumetric Flow Rate: **110,000** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):				
2. Source Classification Code (SCC):			3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:			6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:			9. Million Btu per SCC Unit:
10. Segment Comment:				

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):				
2. Source Classification Code (SCC):			3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:			6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:			9. Million Btu per SCC Unit:
10. Segment Comment:				

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	018		WP
PM10	018		WP

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.022** lb/hour **0.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.72 lb/ton of dry wood** Reference: **AP-42, Table 10.6-1**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table 3-6 in Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Method 9 VE Test**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.002** lb/hour **0.01** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.062 lb/ton of dry wood** Reference: **AP-42 Table 10.6-1**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table 3-6 in Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Method 9 VE Test**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype: VE05	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: Initial Method 9 VE Test.	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: **N/A** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: **N/A** ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☒ Attached, Document ID: **See Report** ☐ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☒ Attached, Document ID: **See Report** ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: **See Report** ☐ Not Applicable	
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☐ Attached, Document ID: _____ ☐ Not Applicable	
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☐ Not Applicable	
3. Alternative Methods of Operation: ☐ Attached, Document ID: _____ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☐ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   One nominal 62 MMBtu/hr natural gas boiler.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**1/2012**	**1/2013**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment: **One natural gas-fired boiler is being permitted to assist with startup operations. The emissions unit is regulated under the NSPS, Subpart Dc standards.**

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description: **None**
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **62** million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **500** hours/year
6. Operating Capacity/Schedule Comment: **The boiler is to be used for startup operations only, estimated to be approximately 500 hr/yr.**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **See Report**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **50** feet	7. Exit Diameter: **2.75** feet
8. Exit Temperature: **296**°F	9. Actual Volumetric Flow Rate: **29,000** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Table 3-7 presents emission point information.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **Natural gas**		
2. Source Classification Code (SCC):	3. SCC Units: **Million cubic feet**	
4. Maximum Hourly Rate: **0.06**	5. Maximum Annual Rate: **31.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2 gr/100 scf**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **980**
10. Segment Comment: **Maximum annual rate based on 500 hr/yr operation.**		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			NS
PM/PM10	Fuel Quality		NS
NOx			EL
SO2	Fuel Quality		WP
VOC			NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.96** lb/hour **1.24** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.08 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.08 lb/MMBtu x 62 MMBtu/hr = 4.96 lb/hr** **4.96 lb/hr x 500 hr/yr / (2,000 lb/ton) = 1.24 tons per year**	
11. Potential, Fugitive, and Actual Emissions Comment: **Report, Section 3.0, Table 3-7.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **5.89** lb/hour **1.47** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.095 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.095 lb/MMBtu x 62 MMBtu/hr = 5.89 lb/hr** **5.89 lb/hr x 500 hr/yr / (2,000 lb/ton) = 1.47 tons per year**	
11. Potential, Fugitive, and Actual Emissions Comment: **Report, Section 3.0, Table 3-7.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.095 lb/MMBtu**	4. Equivalent Allowable Emissions: **5.89** lb/hour **1.47** tons/year
5. Method of Compliance: **Manufacturer Certification**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.35** lb/hour **0.09** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 gr/100 scf** Reference: **AP-42**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Section 3.0, Table 3-7.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 gr/100 scf**	4. Equivalent Allowable Emissions: **0.35** lb/hour **0.09** tons/year
5. Method of Compliance: **Fuel Vendor Information**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.12** lb/hour **0.03** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.90 lb/10^6 scf - filterable PM** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Section 3.0, Table 3-7.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% opacity**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.31** lb/hour **0.08** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.005 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.005 lb/MMBtu x 62 MMBtu/hr = 0.31 lb/hr** **0.31 lb/hr x 500 hr/yr / (2,000 lb/ton) = 0.08 tons per year**	
11. Potential, Fugitive, and Actual Emissions Comment: **See Report, Section 2.0, Table 2-7.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Excess emissions provided by Rule 62-210.700.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date ____
2.	Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date ____
3.	Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date ____
4.	Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable (construction application)
5.	Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____ ☒ Not Applicable
6.	Compliance Demonstration Reports/Records: ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute: ☒ Attached, Document ID: **See Report** ☐ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID:_____	☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID:_____	☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID:_____	☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☐ Attached, Document ID: _____	☐ Not Applicable
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____	☐ Not Applicable
3. Alternative Methods of Operation: ☐ Attached, Document ID: _____	☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____	☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
☒ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Flare System.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**1/2012**	**9/2013**	**49**

8. Federal Program Applicability: (Check all that apply)

☐ Acid Rain Unit
☐ CAIR Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
Two flares are provided as a means of emergency venting. There are 3 modes of operation under which the flare system may potentially be needed: 1) startup, 2) planned shutdown and 3) emergency shutdown.

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **469** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day days/week weeks/year **100** hours/year	
6. Operating Capacity/Schedule Comment: **The number of operating hours is based on as many as 6 startup/shutdowns per year and a conservative estimate of 100 hours per year.**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **See Report**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **TBD** feet	7. Exit Diameter: **1** feet
8. Exit Temperature: **TBD**°F	9. Actual Volumetric Flow Rate: **TBD** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): North (km):		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Table 3-8 presents emission point information.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **Product Gas**			
2. Source Classification Code (SCC):		3. SCC Units: **1,000,000 SCF**	
4. Maximum Hourly Rate: **1.07**	5. Maximum Annual Rate: **107.7**		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit: **435.4**
10. Segment Comment: **Maximum annual rate based on 100 hr/yr operation. See Table 3-8 of Report.**			

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):			
2. Source Classification Code (SCC):		3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment:			

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			WP
PM/PM10			WP
NOx			WP
SO2			WP
VOC			WP

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **173** lb/hour **9.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.37 lb/MMBtu** Reference: **AP-42, Table 13.5-1.**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table 3-8 of the Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **32** lb/hour **2.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.068 lb/MMBtu** Reference: **AP-42, Table 13.5-1**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Table 3-8.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.9** lb/hour **0.05** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Table 3-8** Reference:	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Table 3-8.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **See Report, Table 3-8**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Report, Table 3-8.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **65.0** lb/hour **3.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.14 lb/MMBtu** Reference: **AP-42, Table 13.5-1**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See report, Table 3-8.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **1**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Excess emissions provided by Rule 62-210.700.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☒ Attached, Document ID: **See Report** ☐ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☒ Attached, Document ID: **See Report** ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ☒ Not Applicable	
3. Description of Stack Sampling Facilities : (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☐ Attached, Document ID: _____ ☐ Not Applicable	
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☐ Not Applicable	
3. Alternative Methods of Operation: ☐ Attached, Document ID: _____ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☐ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
   ☒ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Mechanical Draft Cooling Towers associated with the Steam Turbine and Compressor Gas Systems.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**1/2010**	**9/2010**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit
   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **TBD** Model Number: **TBD**

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

See Report, Table 3-9. A 2-cell wet mechanical draft cooling tower for steam turbine cooling and a 3-cell cooling tower for compressor gas cooling.

<u>Emissions Unit Control Equipment/Method:</u> Control 1 of 1

1. Control Equipment/Method Description: **Mist Eliminators.**	
2. Control Device or Method Code: **014**	

<u>Emissions Unit Control Equipment/Method:</u> Control ___ of ___

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

<u>Emissions Unit Control Equipment/Method:</u> Control ___ of ___

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

<u>Emissions Unit Control Equipment/Method:</u> Control ___ of ___

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **7,050 gpm and 3,800 gpm**		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: million Btu/hr		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day	**7** days/week
	52 weeks/year	**8,760** hours/year
6. Operating Capacity/Schedule Comment: **See Report, Table 3-9 for cooling tower performance and emissions data.**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **See Report, ID No. 6**		2. Emission Point Type Code:
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Cooling Tower Cells**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code:	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **See Report, Table 3-9.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	014		WP
PM10	014		WP

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.23** lb/hour **1.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Report, Table 3-9.** Reference: **Solar, 2008; Golder, 2008**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Potential emissions are for both cooling towers, see Table 3-9 in Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **percent of CW**	4. Equivalent Allowable Emissions: **0.23** lb/hour **1.0** tons/year
5. Method of Compliance: **Design drift rate certification from manufacturer.**	
6. Allowable Emissions Comment (Description of Operating Method): **CW = circulating water.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.17** lb/hour **0.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Report, Table 3-9.** Reference: **Solar, 2008; Golder, 2008**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Potential emissions are for both cooling towers. See Table 3-9 in Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **percent of CW**	4. Equivalent Allowable Emissions: **0.17** lb/hour **0.7** tons/year
5. Method of Compliance: **Design drift rate certification from manufacturer.**	
6. Allowable Emissions Comment (Description of Operating Method): **CW = circulating water.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

<u>Visible Emissions Limitation:</u> Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

<u>Visible Emissions Limitation:</u> Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: N/A ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: See Report ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute:
   ☒ Attached, Document ID: See Report ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID: ____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ____ ☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☐ Attached, Document ID: ____ ☐ Not Applicable
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: ____ ☐ Not Applicable
3. Alternative Methods of Operation: ☐ Attached, Document ID: ____ ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: ____ ☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Material handling associated with the biomass gasification project. Includes transfer and storage of feedstock, ash and olivine.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**1/2010**	**9/2010**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment: **The material handling for feedstock is depicted in Figure 2-4 and 2-5 of the Report. The ash and olivine transfer and storage systems are depicted in Figure 2-6. Emissions estimates are presented in Table 3-5.**

Emissions Unit Control Equipment/Method: Control **1** of **1**

1. Control Equipment/Method Description: **Baghouse control systems.**
2. Control Device or Method Code: **018**

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **See Report, Section 3.0**		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **See Report**		2. Emission Point Type Code:
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code:	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):			
2. Source Classification Code (SCC):		3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment:			

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type):			
2. Source Classification Code (SCC):		3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit:
10. Segment Comment:			

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	018		WP
PM10	018		WP

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **13.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table 3-5 in Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **6.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table 3-5 in Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: **N/A** ☐ Previously Submitted, Date ____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: **N/A** ☐ Previously Submitted, Date ____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Report** ☐ Previously Submitted, Date ____

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date ____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   ☒ Attached, Document ID: **See Report** ☐ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☒ Attached, Document ID: **See Report** ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ☒ Not Applicable	
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☐ Attached, Document ID: ____ ☐ Not Applicable	
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: ____ ☐ Not Applicable	
3. Alternative Methods of Operation: ☐ Attached, Document ID: ____ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: ____ ☐ Not Applicable	

Additional Requirements Comment

ATTACHMENT NWF-FI-C1
ACID RAIN PART APPLICATION (DEP FORM NO. 62-210.900(1)(A))

Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30, 72.31, and 74; and Chapter 62-214, F.A.C.

This submission is: X New ☐ Revised ☐ Renewal

STEP 1

Identify the source by plant name, state, and ORIS or plant code.

Plant name	State	ORIS/Plant Code
NWFREC, LLC	**FL**	**TBD**

STEP 2
Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a."

If unit a SO_2 Opt-in unit, enter "yes" in column "b".

For new units or SO_2 Opt-in units, enter the requested information in columns "d" and "e."

a	b	c	d	e
Unit ID#	SO_2 Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO_2 Opt-in Units Commence Operation Date	New or SO_2 Opt-in Units Monitor Certification Deadline
001A	**N**	Yes		
001B	**N**	Yes		
001C	**N**	Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

NWFREC, LLC

Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain Part application (including a compliance plan) under 40 CFR Part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the DEP determines is necessary in order to review an Acid Rain Part application and issue or deny an Acid Rain Part;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain Part application or a superseding Acid Rain Part issued by the DEP; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.
(4) For applications including a SO_2 Opt-in unit, a monitoring plan for each SO_2 Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO_2 Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000, or the deadline for monitor certification under 40 CFR Part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain Part application, the Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the DEP:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from STEP 1) **NWFREC, LLC**

Recordkeeping and Reporting Requirements (cont)

STEP 3, Continued.

(iv) Copies of all documents used to complete an Acid Rain Part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I, and 40 CFR Part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_X averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

STEP 4
For SO_2 Opt-in units only.

In column "f" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" of STEP 2.

For column "g" describe the combustion unit and attach information and diagrams on the combustion unit's configuration.

In column "h" enter the hours.

f	g	h (not required for renewal application)
Unit ID#	Description of the combustion unit	Number of hours unit operated in the six months preceding initial application

Plant Name (from STEP 1)	NWFREC, LLC

STEP 5

For SO_2 Opt-in units only.
(Not required for SO_2 Opt-in renewal applications.)

In column "i" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" (and in column "f").

For columns "j" through "n," enter the information required under 40 CFR 74.20-74.25 and attach all supporting documentation required by 40 CFR 74.20-74.25.

i	j	k	l	m	n
Unit ID#	Baseline or Alternative Baseline under 40 CFR 74.20 (mmBtu)	Actual SO_2 Emissions Rate under 40 CFR 74.22 (lbs/mmBtu)	Allowable 1985 SO_2 Emissions Rate under 40 CFR 74.23 (lbs/mmBtu)	Current Allowable SO_2 Emissions Rate under 40 CFR 74.24 (lbs/mmBtu)	Current Promulgated SO_2 Emissions Rate under 40 CFR 74.25 (lbs/mmBtu)

STEP 6

For SO_2 Opt-in units only.

Attach additional requirements, certify and sign.

A. If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in 40 CFR 74.47 for combustion sources must be attached.
B. A statement whether the combustion unit was previously an affected unit under 40 CFR 74.
C. A statement that the combustion unit is not an affected unit under 40 CFR 72.6 and does not have an exemption under 40 CFR 72.7, 72.8, or 72.14.
D. Attach a complete compliance plan for SO_2 under 40 CFR 72.40.
E. The designated representative of the combustion unit shall submit a monitoring plan in accordance with 40 CFR 74.61. For renewal application, submit an updated monitoring plan if applicable under 40 CFR 75.53(b).
F. The following statement must be signed by the designated representative or alternate designated representative of the combustion source: "I certify that the data submitted under 40 CFR Part 74, Subpart C, reflects actual operations of the combustion source and has not been adjusted in any way."

Signature	Date

STEP 7

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Certification (for designated representative or alternate designated representative only)

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **Kenn Davis**	Title **Project Manager**
Owner Company Name **BIOMASS ENERGY HOLDINGS, LLC**	
Phone **(765) 832-8526**	E-mail address **kdavis@**bioeh.com
Signature Kenn Davis	Date Jan. 31, 2011

ATTACHMENT NWF-FI-C2
(EPA FORM 7610-1)

EPA

Certificate of Representation

For more information, see instructions and 40 CFR 72.24; 40 CFR 96.113, 96.213, or 96.313, or a comparable state regulation under the Clean Air Interstate Rule (CAIR) NO_X Annual, SO_2, and NO_X Ozone Season Trading Programs or 40 CFR 97.113, 97.213, or 97.313.

FACILITY (SOURCE) INFORMATION

This submission is: X New ~ Revised (revised submissions must be complete; see instructions)

STEP 1
Provide information for the facility (source).

Facility (Source) Name **NWFREC, LLC**	State **FL**	Plant Code **TBD**
County Name **Gulf**		
Latitude	Longitude	

STEP 2
Enter requested information for the designated representative.

Name **Kenn Davis**	Title **Project Manager**
Company Name **Biomass Energy Holdings, LLC**	
Address **P.O. Box 366, Clinton, Indiana 47842**	
Phone Number **(765) 832-8526**	Fax Number **(765) 832-1860**
E-mail address **kdavis@bioeh.com**	

STEP 3
Enter requested information for the alternate designated representative.

Name	Title
Company Name	
Address	
Phone Number	Fax Number
E-mail address	

Facility (Source) Name (from Step 1) **NWFREC, LLC**

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_X Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ~ CAIR NO_X Annual ~ CAIR SO_2 ~ CAIR NO_X Ozone Season

				Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR Nameplate Capacity (MWe)
Unit ID# **001A**	Unit Type **CT**	Source Category **Industrial Turbine**		**Solar Model T-130**	**16**	
		NAICS Code **22-Utilities**				
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):			Check One: Actual ~ Projected ~			

Company Name: **Biomass Energy Holdings, LLC**	X Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator

Facility (Source) Name (from Step 1) **NWFREC, LLC**

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_X Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ~ CAIR NO_X Annual ~ CAIR SO_2 ~ CAIR NO_X Ozone Season

Unit ID# **001B**	Unit Type **CT**	Source Category **Industrial Turbine** NAICS Code **22-Utilities**		Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR Nameplate Capacity (MWe)
				Solar Model T-130	**16**	
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):			Check One: Actual ~ Projected ~			

Company Name	Owner/Operator
Company Name: **Biomass Energy Holdings, LLC**	X Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator

Facility (Source) Name (from Step 1) **NWFREC, LLC**

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_X Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ~ CAIR NO_X Annual ~ CAIR SO_2 ~ CAIR NO_X Ozone Season

Unit ID# **001C**	Unit Type **CT**	Source Category **Industrial Turbine** / NAICS Code **22-Utilities**	Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR Nameplate Capacity (MWe)
			Solar Model T-130	**16**	
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):		Check One: Actual ~ Projected ~			

Company Name	Owner / Operator
Company Name: **Biomass Energy Holdings, LLC**	X Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator
Company Name:	~ Owner ~ Operator

STEP 5: Read the appropriate certification statements, sign, and date.

Acid Rain Program

I certify that I was selected as the designated representative or alternate designated representative (as applicable) by an agreement binding on the owners and operators of the affected source and each affected unit at the source (i.e., the source and each unit subject to the Acid Rain Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and each affected unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the affected source and each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under a life-of-the-unit, firm power contractual arrangement,
I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the affected source and each affected unit at the source; and
>
> Allowances, and proceeds of transactions involving allowances, will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of allowances, allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_X Annual Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_X source and each CAIR NO_X unit at the source (i.e., the source and each unit subject to the CAIR NO_X Annual Trading Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_X Annual Trading Program on behalf of the owners and operators of the CAIR NO_X source and each CAIR NO_X unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_X source and each CAIR NO_X unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_X unit, or where a utility or industrial customer purchases power from a CAIR NO_X unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

> I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_X source and each CAIR NO_X unit at the source; and
>
> CAIR NO_X allowances and proceeds of transactions involving CAIR NO_X allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_X allowances by contract, CAIR NO_X allowances and proceeds of transactions involving CAIR NO_X allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) SO_2 Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source (i.e., the source and each unit subject to the SO_2 Trading Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR SO_2 Trading Program, on behalf of the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO_2 unit, or where a utility or industrial customer purchases power from a CAIR SO_2 unit under a life-of-the-unit, firm power contractual arrangement,
I certify that:

> I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR SO_2 source and each CAIR SO_2 unit at the source; and
>
> CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO_2 allowances by contract, CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_X Ozone Season Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source (i.e., the source and each unit subject to the CAIR NO_X Ozone Season Trading Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_X Ozone Season Trading Program on behalf of the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_x Ozone Season unit, or where a utility or industrial customer purchases power from a CAIR NO_x Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

> I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit; and
>
> CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_x Ozone Season allowances by contract, CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.

Facility (Source) Name (from Step 1) **NWFREC, LLC**

General

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (Designated Representative)	Date
Signature (Alternate Designated Representative)	Date

APPENDIX A
VENDOR DATA

NORTHWEST FLORIDA RENEWABLE ENERGY
Biomass Energy Holdings

PROJECT EMISSIONS

Guaranteed Emissions at Full Load Operations

Rev A: Original
Rev B: No changes in emissions - changes in Silva Steam to reflect reduced fuel production
Rev C: Revised Fired Case capacity, added stack dia of 78 inches
Rev D: Changed to 59F combustion air, added water inject to Turbine, added CO Catalyst
Rev E: Changed GTU Pm emissions to 0.03
Rev F: Changed format for DOE requirements
Rev G: Changed Nox emission rates
Rev H: Updated based on updated emissions analysis using WI, and minimum 80% Turbine Operation for emissions statement
Rev I: Revised to 3 GTU, Unfired HRSGs, 55F/99% RH Inlet air chilling
Rev J: Correct typo, Post SCR Nox pph

Unfired HRSG Design

Fuel Available 468.5 MMBtu/hr LHV

Nox Reduction: 87.0%
CO Reduction: 70%

EMISSIONS ARE FOR ONE UNIT TRAIN @ 100% LOAD - THREE REQUIRED

	Gas Turbine Outlet (80-100% for Nox & UHC, 80%-100% CO)						After Boiler Section / Before SCR & CO Catalysts					After SCR Nox & CO Reductions (Stack Outlet)					
Ambient Temp F	GTU Exh Flow pph	Exh Temp F	Nox ppm	CO ppm	UHC ppm	NH3 ppm	Mass Flow pph	Nox ppm	CO ppm	UHC ppm	NH3 ppm	Stack Exh Flow pph	Exh Temp F	Nox ppm	CO ppm	UHC ppm	NH3 ppm
55	409,957	929	115.00	50.00	25.00	NA	409,957	115.0	50.0	25.0	NA	409,957	326	15.0	15.0	25.0	10.0
55		pph	69.13	18.30	5.23	NA		69.13	18.30	5.23	NA			8.99	5.5	5.2	2.4
55		TPY	302.8	80.2	22.9	NA		302.8	80.2	22.9	NA			39.5	24.0	22.9	10.4

NOTES: No emissions guaranteed below 80% of Turbine Load

Available Silva Fuel for Usage

Temp F:	55	
Total Fuel Available:	468.5	MMBtu/hr LHV
Fuel/Train:	156.2	MMBtu/hr LHV

Fuel MMBtu/hr LHV Used

	GTU
Temp F:	55
Each:	156.2
Total:	468.5

Stack Diameter 78 inches

Total Unfired Steam Full Load

Ambient Temp F	HRSG 1	HRSG 2	HRSG 3	Total Seam Production
55	50,642	50,642	50,642	151,926

Notes:

1) All Emissions Are Based on 8,760 Annual Hours of Operation
2) HRSG Stack Diameter is 78 inches

APPENDIX B
MATERIAL HANDLING EMISSION ESTIMATES

TABLE Appendix B-1
MATERIAL HANDLING EMISSION ESTIMATES (STACK-OUT)
Project: Port St. Joe

Parameters		**Units**	TRUCK PAVED ROADS Delivery of wood	TRUCK DUMP TO HOPPER	HOPPER TO CONVERED CONVEYOR	COVERED CONVEYOR TO SCREEN	SCREEN TO COVERED CONVEYOR	SCREEN TO HOG MILL	HOG MILL TO COVERED CONVEYOR	COVERED CONVEYOR TO STACKER	STACKER TO PILE	OPEN PILE Wind Erosion
		Flow Diagram ID	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10
Emission Point/Area												
Operational Data												
Activity, hours	Daily	(hrs/day)	4	4	4	4	4	4	4	4	4	24
days	Annual	(days/yr)	365	365	365	365	365	365	365	365	365	365
Material Handling Data												
Material type			Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips
Material throughput, ton/hr (design)			300	300	300	300	200	100	100	300	300	300
ton/day	Daily	(tons/day)	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152
ton/yr	Annual	(tons/yr)	420,480	420,480	420,480	420,480	280,320	140,160	140,160	420,480	420,480	420,480
Moisture content (M), % (nominal)		%	30	30	30	30	30	30	30	30	30	30
Number of transfers		No.		1	1	1	1	1	1	1	1	
Miles per day of road transport	Daily Avg = Annual Avg	No.	35	NA	NA	NA	NA	NA	NA	NA	NA	
Miles per truck round trip	Daily Avg = Annual Avg	No.	0.61	NA	NA	NA	NA	NA	NA	NA	NA	
Number of truck trips	Daily Avg = Annual Avg	No.	58	NA	NA	NA	NA	NA	NA	NA	NA	
Storage Pile Data												
Pile Description (shape)												Circular
Average Pile Height (ft)												40
Pile Diameter (ft)												330
Uncovered Conveyor												
Description (shape)												
Average Pile Height (ft)												
Conveyor Length (ft)												
Conveyor Width (ft)												
Size, ft^2												85,487
Size, acres												1.97
General/ Site Characteristics												
Mean wind speed, mph	Daily	mph	14.76	14.76	14.76	14.76	14.76	14.76	14.76	14.76	14.76	14.76
	Annual	mph	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38
Particle size multiplier, PM (k)			0.082	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	1.00
Particle size multiplier, PM10 (k)			0.016	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.50
Particle size multiplier, PM2.5 (k)			0.002	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.075
Days of precipitation greater than or	Short term											0
equal to 0.01 inch (p)	Annual											61
Time (%) that unobstructed wind speed	Short term											76.5
exceeds 5.4 m/s at mean pile height (f)	Annual	61										15.3
Silt content (s), %												0.25
Emission Control Data												
Emission control method			None	Open	Low drop Point	Low drop Point	Low drop Point	Baghouse Control	Baghouse Control	Low drop Point	Height of the stacker discharge onto the pile is automatically controlled to keep the drop to a minimum	Open Pile with water sprays
Emission control removal efficiency, %		%	0	0	70	70	70	99	99	70	70	60
Emission Factor (EF) Equations for Transfer Operations												
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = k x (0.0032) x $(U / 5)^{1.3}$/[$(M / 2)^{1.4}$]	(lb/ton)										
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]	(lb/ton)										
Emission Factor (E) Equation for Unpaved Roads (Front End Loaders)												
Uncontrolled EF (UEF) Equation	UEF=k x $(s/12)^a$ x $(w/3)^b$; where a = 0.7 and b= 0.45, k = 4.9 for TSP w = 55 tons (e.g., CAT 988): a=0.9 for PM10 and PM2.5	(lb/mile)										
Controlled EF (CEF) Equation	CEF=k x (s/12)a x $(w/3)^b$ x [100% - Removal efficiency (%)] Accounting for rainfall using (1-P/(4 x365)) Where: P = 61, therefore control = (1-61/4/365) = 0.958											
Emission Factor (E) Equation for Paved Roads												
Uncontrolled EF (UEF) Equation	UEF=[k x $(sl/2)^a$ x $(w/3)^b$ -C] where a = 0.65 and b = 1.5, k = 0.082 for TSP, C = 0.00047 sl = 1 based on Golder 2001 Port Transportation Study w = 32.5 tons full truck, 12.5 tons empty truck	(lb/mile)										
Controlled EF (CEF) Equation	CEF=[k x $(sl/2)^a$ x $(w/3)^b$ -C] x (1-P/(4 x365)) x [100% - Removal efficiency (%)] Accounting for rainfall using (1-P/(4 x365)) Where: P = 61, therefore control = (1-61/4/365) = 0.958											
Emission Factor (E) Equation for Wind Erosion												
Uncontrolled EF (UEF) Equation	UEF (lb/day/acre) = k x 1.7 x (s/1.5) x ((365 - p)/235) x (f/15)											
Controlled (Final) EF (CEF) Equation	CEF (lb/day/acre) = UEF (lb/day/acre) x (100 - Removal efficiency (%))											
Calculated PM Emission Factor (EF)												
Uncontrolled EF	Short term		1.072867 (lb/mile)	0.00022 (lb/ton)	0.00022 (lb/ton)	0.00022 (lb/ton)	0.00022 (lb/ton)	0.00022 (lb/ton)	0.00022 (lb/ton)	0.00022 (lb/ton)	0.00022 (lb/ton)	2.2 (lb/day/acre)
	Annual		1.072867 (lb/mile)	0.00009 (lb/ton)	0.00009 (lb/ton)	0.00009 (lb/ton)	0.00009 (lb/ton)	0.00009 (lb/ton)	0.00009 (lb/ton)	0.00009 (lb/ton)	0.00009 (lb/ton)	0.4 (lb/day/acre)
Controlled EF	Short term		1.027807 (lb/mile)	0.00022 (lb/ton)	0.00007 (lb/ton)	0.00007 (lb/ton)	0.00007 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00007 (lb/ton)	0.00007 (lb/ton)	0.9 (lb/day/acre)
	Annual		1.027807 (lb/mile)	0.00009 (lb/ton)	0.00003 (lb/ton)	0.00003 (lb/ton)	0.00003 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00003 (lb/ton)	0.00003 (lb/ton)	0.1 (lb/day/acre)
Calculated PM10 Emission Factor (EF)												
Uncontrolled EF, lb/ton	Short term		0.208962 (lb/mile)	0.00010 (lb/ton)	0.00010 (lb/ton)	0.00010 (lb/ton)	0.00010 (lb/ton)	0.00010 (lb/ton)	0.00010 (lb/ton)	0.00010 (lb/ton)	0.00010 (lb/ton)	1.1 (lb/day/acre)
	Annual		0.208962 (lb/mile)	0.00004 (lb/ton)	0.00004 (lb/ton)	0.00004 (lb/ton)	0.00004 (lb/ton)	0.00004 (lb/ton)	0.00004 (lb/ton)	0.00004 (lb/ton)	0.00004 (lb/ton)	0.2 (lb/day/acre)
Controlled EF, lb/ton	Short term		0.200185 (lb/mile)	0.00010 (lb/ton)	0.00003 (lb/ton)	0.00003 (lb/ton)	0.00003 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00003 (lb/ton)	0.00003 (lb/ton)	0.4 (lb/day/acre)
	Annual		0.200185 (lb/mile)	0.00004 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.1 (lb/day/acre)
Calculated PM2.5 Emission Factor (EF)												
Uncontrolled EF, lb/ton	Short term		0.031055 (lb/mile)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.2 (lb/day/acre)
	Annual		0.031055 (lb/mile)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.0 (lb/day/acre)
Controlled EF, lb/ton	Short term		0.029750 (lb/mile)	0.00002 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.1 (lb/day/acre)
	Annual		0.029750 (lb/mile)	0.00001 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.0 (lb/day/acre)
Estimated Emission Rate (CER)												
PM ER	lb/hr (daily basis)		9.019006	0.06288	0.01886	0.01886	0.01886	0.0006288	0.0006288	0.01886	0.01886	0.07351
	TPY		6.583874	0.01864	0.00559	0.00559	0.00373	0.0000621	0.0000621	0.00559	0.00559	0.05363
PM10 ER	lb/hr (daily basis)		0.292771	0.02974	0.00892	0.00892	0.00892	2.97E-04	0.0002974	0.00892	0.00892	0.03676
	TPY		1.282337	0.00882	0.00265	0.00265	0.00176	0.0000294	0.0000294	0.00265	0.00265	0.02682
PM2.5 ER	lb/hr (daily basis)		0.043510	0.00450	0.00135	0.00135	0.00135	4.50E-05	0.0000450	0.00135	0.00135	0.00551
	TPY		0.190574	0.00134	0.00040	0.00040	0.00027	0.0000045	0.0000045	0.00040	0.00040	0.00402

Source: USEPA, 2006; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles. Section 13.2.1.3 for Paved Roads. Seciton 13.2.2 for Unpaved Roads. USEPA, 1993; Emission Factor Documentation for AP-42, Section 13.2.1 Paved Roads..
USEPA, 1992 (Fugitive Dust Background and Technical Information Document for Best Available Control Measures, Section 2.3.1.3.3, Wind Emissions from Continuously Active Piles). USEPA, 2006 13.2.5 for k factors.

TABLE B-1A
MATERIAL HANDLING EMISSION ESTIMATES
TRUCK TRAFFIC - ASH TRUCKS

Parameters		**TRUCK TRAFFIC Shipping of Ash**
Material Handling Data		
Material type		Ash
Material throughput, ton/hr [a]		0.00
ton/day	Daily	40
ton/yr	Annual	14,600
Truck Capacity (tons)	Capacity	25
Vehicle weight (W) (tons)	Unloaded	12.5
	Loaded	37.5
	Average	25
Number of truck trips	Daily Avg/ Annual Avg	2.0
Number of miles/per truck round trip	Daily Avg/ Annual Avg	0.61
Total road transport (miles/day)	Daily Avg	1.22
Total road transport (miles/yr)	Annual Avg	356
General/ Site Characteristics		
Particle size multiplier, PM (k)		0.082
Particle size multiplier, PM10 (k)		0.016
Particle size multiplier, PM2.5 (k)		0.0024
Days of precipitation greater than or	Short term	0
equal to 0.01 inch (P)	Annual	61
Silt loading (sL) (g/m^2) [b]		1
Emission Factor Fleet Exhaust (C), lb/VMT		0.00047
Emission Control Data		
Emission control method		None
Emission control removal efficiency, %		0
Emission Factor (E) Equation for Paved Roads		
Uncontrolled EF (UEF) Equation	UEF (lb/mile) = $[k \times (sL/2)^{0.65} \times (W/3)^{1.5} - C]$ (1 - 1.2P/N), hourly basis where N = 8760	
Controlled EF (CEF) Equation	CEF(lb/mile) = CEF(lb/mile) x [100% - Removal efficiency (%)]	
Calculated PM Emission Factor (EF)		
Uncontrolled EF, lb/mile	Short term	1.257
	Annual	1.246
Controlled EF, lb/mile	Short term	1.257
	Annual	1.246
Calculated PM10 Emission Factor (EF)		
Uncontrolled EF, lb/mile	Short term	0.245
	Annual	0.243
Controlled EF, lb/mile	Short term	0.245
	Annual	0.243
Calculated PM2.5 Emission Factor (EF)		
Uncontrolled EF, lb/mile	Short term	0.036
	Annual	0.036
Controlled EF, lb/mile	Short term	0.036
	Annual	0.036
Estimated Emission Rate (CER)		
PM ER lb/hr (daily basis)		0.064
TPY		0.222
PM10 ER lb/hr (daily basis)		0.012
TPY		0.043
PM2.5 ER lb/hr (daily basis)		0.002
TPY		0.0064

Source: USEPA, 2006; AP-42, Section 13.2.1.3 for Paved Roads. Factor Documentation for AP-42, Section 13.2.1 Paved Roads..

[a] Based on Ash Content of wood equal to 1.2%

[b] Based on Golder 2001 Port Transportation Study

TABLE B-2
MATERIAL HANDLING EMISSION ESTIMATES (RECLAIM)
Project: Port St. Joe

Parameters		**Units** **Flow Diagram ID**	Chain Drag to Reclaim Conveyor 1 R1	Reclaim Conveyor 1 to Reclaim Conveyor 2 R2	Conveyor 2 to Suply Conveyor 3 R3	Supply Conveyor 3 to Dryer R4	Dryer to Conveyor R5	Conveyor to Day Bin R6	Day Bin to Bucket Elevator R7	Bucket Elevator to Gasifier R8	
Emission Point/Area											
Operational Data											
Activity, hours	Daily	(hrs/day)	24	24	24	24	24	24	24	24	
days	Annual	(days/yr)	365	365	365	365	365	365	365	365	
Material Handling Data											
Material type			Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips	Wood Chips	
Material throughput, ton/hr (design)			100	100	100	100	100	100	48	48	
ton/day	Daily	(tons/day)	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152	
ton/yr	Annual	(tons/yr)	420,480	420,480	420,480	420,480	420,480	420,480	420,480	420,480	
Moisture content (M), % (nominal)		%	30	30	30	30	23	23	23	23	
Number of transfers		No.	1	1	1	1	1	1	1	1	
Miles per day of road transport	Daily Avg = Annual Avg	No.	NA	NA	NA	NA	NA	NA	NA	NA	
Miles per truck round trip	Daily Avg = Annual Avg	No.	NA	NA	NA	NA	NA	NA	NA	NA	
Number of truck trips	Daily Avg = Annual Avg	No.	NA	NA	NA	NA	NA	NA	NA	NA	
General/ Site Characteristics											
Mean wind speed, mph	Daily	mph	14.76	14.76	14.76	14.76	14.76	14.76	14.76	14.76	
	Annual	mph	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	
Particle size multiplier, PM (k)			0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	
Particle size multiplier, PM10 (k)			0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	
Particle size multiplier, PM2.5 (k)			0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	
Emission Control Data											
Emission control method			Low drop Point	Low drop Point	Baghouse Controlled	Low drop Point	Low drop Point	Baghouse Controlled	Enclosed	Enclosed	
Emission control removal efficiency, %		%	70	70	99	70	70	99	95	95	
Emission Factor (EF) Equations for Transfer Operations											
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = k x (0.0032) x $(U / 5)^{1.3}/[(M / 2)^{1.4}]$	(lb/ton)									
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]	(lb/ton)									
Calculated PM Emission Factor (EF)											
Uncontrolled EF	Short term		0.00022 (lb/ton)	0.00022 (lb/ton)	0.00022 (lb/ton)	0.00022 (lb/ton)	0.00032 (lb/ton)	0.00032 (lb/ton)	0.00032 (lb/ton)	0.00032 (lb/ton)	
	Annual		0.00009 (lb/ton)	0.00009 (lb/ton)	0.00009 (lb/ton)	0.00009 (lb/ton)	0.00013 (lb/ton)	0.00013 (lb/ton)	0.00013 (lb/ton)	0.00013 (lb/ton)	
Controlled EF	Short term		0.00007 (lb/ton)	0.00007 (lb/ton)	0.00000 (lb/ton)	0.00007 (lb/ton)	0.00010 (lb/ton)	0.00000 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	
	Annual		0.00003 (lb/ton)	0.00003 (lb/ton)	0.00000 (lb/ton)	0.00003 (lb/ton)	0.00004 (lb/ton)	0.00000 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	
Calculated PM10 Emission Factor (EF)											
Uncontrolled EF, lb/ton	Short term		0.00010 (lb/ton)	0.00010 (lb/ton)	0.00010 (lb/ton)	0.00010 (lb/ton)	0.00015 (lb/ton)	0.00015 (lb/ton)	0.00015 (lb/ton)	0.00015 (lb/ton)	
	Annual		0.00004 (lb/ton)	0.00004 (lb/ton)	0.00004 (lb/ton)	0.00004 (lb/ton)	0.00006 (lb/ton)	0.00006 (lb/ton)	0.00006 (lb/ton)	0.00006 (lb/ton)	
Controlled EF, lb/ton	Short term		0.00003 (lb/ton)	0.00003 (lb/ton)	0.00000 (lb/ton)	0.00003 (lb/ton)	0.00004 (lb/ton)	0.00000 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	
	Annual		0.00001 (lb/ton)	0.00001 (lb/ton)	0.00000 (lb/ton)	0.00001 (lb/ton)	0.00002 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	
Calculated PM2.5 Emission Factor (EF)											
Uncontrolled EF, lb/ton	Short term		0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	0.00002 (lb/ton)	
	Annual		0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	0.00001 (lb/ton)	
Controlled EF, lb/ton	Short term		0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00001 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	
	Annual		0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	0.00000 (lb/ton)	
Estimated Emission Rate (CER)											
PM ER	lb/hr (daily basis)		0.00314	0.00314	0.00010	0.00314	0.00456	0.00015	0.00076	0.00076	0.01577
	TPY		0.00559	0.00559	0.00019	0.00559	0.00811	0.00027	0.00135	0.00135	0.02805
PM10 ER	lb/hr (daily basis)		0.00149	0.00149	4.96E-05	0.00149	0.00216	7.19E-05	0.00036	0.00036	0.00746
	TPY		0.00265	0.00265	0.00009	0.00265	0.00384	0.00013	0.00064	0.00064	0.01327
PM2.5 ER	lb/hr (daily basis)		0.00023	0.00023	7.51E-06	0.00023	0.00033	0.00001	0.00005	0.00005	0.00113
	TPY		0.00040	0.00040	0.00001	0.00040	0.00058	0.00002	0.00010	0.00010	0.00201

Source: USEPA, 2006; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles. Section 13.2.1.3 for Paved Roads. USEPA, 1993; Emission Factor Documentation for AP-42, Section 13.2.1 Paved Roads..
USEPA, 1992 (Fugitive Dust Background and Technical Information Document for Best Available Control Measures, Section 2.3.1.3.3, Wind Emissions from Continuously Active Piles). USEPA, 2006 13.2.5 for k factors.

Note: Material through transfer points R5 through R8 after material dryer, therefore moisture assumed = 5%.

TABLE B-3
SCREEN AND HOG MILL EMISSIONS
Project: Port St. Joe

		PM	PM10	PM2.5	
SCREEN					
	E = EF x W	PM	PM10	PM2.5	
	EF = Emission Factor	0.025	0.0087	0.0087	AP-42 Seciton 11.19.2
	W (average weight)	420,480	420,480	420,480	
	Uncontrolled Emissions (tons/year)	5.256	1.829088	1.829088	
	Control	99%	99%	99%	Enclosure with Baghouse Control
	Emissions (tons/year)	0.05256	0.0182909	0.0182909	
	Emissions (lb/hr)	0.075	0.0261	0.0261	
HOG MILL					
	E = EF x W	PM	PM10	PM2.5	
	EF = Emission Factor	0.02	0.0095	0.0014	"Technical Guidance For Control of Industrial Process Fugitive Particulate Emissions", Table 2-43 Primary Crushing
	W (average weight)	140,160	140,160	140,160	
	Uncontrolled Emissions (tons/year)	1.4016	0.66576	0.098112	
	Control	99%	99%	99%	Enclosure with Baghouse Control
	Emissions (tons/year)	0.014016	0.0066576	0.0009811	
	Emissions (lb/hr)	0.02	0.0095	0.0014	
Total (SCREEN + HOG MILL)					
	Emissions (tons/year)	0.067	0.025	0.019	
	Emissions (lb/hr)	0.0950	0.0356	0.0275	

Source: Golder, 2011.

TABLE B-4
SAND AND ASH HANDLING SYSTEM EMISSIONS

Material	Units	Sand System Baghouse	Ash System Baghouse
Air Flow	scfm	2,500	2,500
Controlled Emissions a	grain/scf	0.03	0.03
PM/PM_{10} Emission Rate	lb/hr	0.64	0.64
	TPY	2.82	2.82
$PM_{2.5}$ Emission Rate[b]	lb/hr	0.64	0.64
	TPY	2.82	2.82

[a] Based on 62-296.711 FAC

[b] $PM_{2.5}$ Emission Rate was based on the different particle size multipliers from EPA's batch drop equation.

Particle size multiplier, PM10 (k) 0.35

Particle size multiplier, PM2.5 (k) 0.053

Source: Golder, 2011

APPENDIX C
LIFE CYCLE ASSESSMENT

Paper No. 18d

LIFE CYCLE ASSESSMENT COMPARISONS OF ELECTRICITY FROM BIOMASS, COAL, AND NATURAL GAS

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ABSTRACT

A series of life cycle assessments (LCA) have been conducted on biomass, coal, and natural gas systems in order to quantify the environmental benefits and drawbacks of each. The power generation options that were studied are: 1) a biomass-fired integrated gasification combined cycle (IGCC) system using a biomass energy crop, 2) a direct-fired biomass power plant using biomass residue, 3) a pulverized coal (PC) boiler representing an average U.S. coal-fired power plant, 4) a system cofiring biomass residue with coal, and 5) a natural gas combined cycle power plant. Each assessment was conducted in a cradle-to-grave manner to cover all processes necessary for the operation of the power plant, including raw material extraction, feed preparation, transportation, waste disposal, and recycling. A summary of the energy balance, global warming potential (GWP), air emissions, and resource consumption for each system is given.

INTRODUCTION

The generation of electricity, and the consumption of energy in general, result in consequences to the environment. Using renewable resources and incorporating advanced technologies such as integrated gasification combined cycle (IGCC) may result in less environmental damage, but to what degree, and with what trade-offs? Life cycle assessment studies have been conducted on various power generating options in order to better understand the environmental benefits and drawbacks of each technology. Material and energy balances were used to quantify the emissions, energy use, and resource consumption of each process required for the power plant to operate. These include feedstock procurement (mining coal, extracting natural gas, growing dedicated biomass, collecting residue biomass), transportation, manufacture of equipment and intermediate materials (e.g., fertilizers, limestone), construction of the power plant, decommissioning, and any necessary waste disposal.

The systems that were studied are:

$ a biomass-fired integrated gasification combined cycle (IGCC) system using a biomass energy crop (hybrid poplar)
$ a direct-fired biomass power plant using biomass residue (urban, primarily)
$ a pulverized coal boiler with steam cycle, representing the average for coal-fired power plants in the U.S. today
$ a system cofiring biomass residue with coal (15% by heat input will be presented here)
$ a natural gas combined cycle power plant.

Each study was conducted independently and can therefore stand alone, giving a complete picture of each power generation technology. However, the resulting emissions, resource consumption, and energy requirements of each system can ultimately be compared, revealing the environmental benefits and drawbacks of the renewable and fossil based systems.

RESULTS

System Energy Balance

The total energy consumed by each system includes the fuel energy consumed plus the energy contained in raw and intermediate materials that are consumed by the systems. Examples of the first type of energy use are the fuel spent in transportation, and fossil fuels consumed by the fossil-based power plants. The second type of energy is the sum of the energy that would be released during combustion of the material (if it is a fuel) and the total energy that is consumed in delivering the material to its point of use. Examples of this type of energy consumption are the use of natural gas in the manufacture of fertilizers and the use of limestone in flue-gas desulfurization. The combustion energy calculation is applied where non-renewable fuels are used, reflecting the fact that the fuel has a potential energy that is being consumed by the system. The combustion energy of renewable resources, those replenished at a rate equal to or greater than the rate of consumption, is not subtracted from the net energy of the system. This is because, on a life cycle basis, the resource is not being consumed. To determine the net energy balance of each system, the energy used in each process block is subtracted from the energy produced by the power plant. The total system energy consumption by each system is shown in Table 1.

Table 1: Total System Energy consumption

System	Total energy consumed (kJ/kWh)
Biomass-fired IGCC using hybrid poplar	231
Direct-fired biomass power plant using biomass residue	125
Average coal	12,575
Biomass / coal cofiring (15% by heat input)	10,118
Natural gas IGCC	8,377

In order to examine the process operations that consume the largest quantities of energy within each system, two energy measurement parameters were defined. First, the energy delivered to the grid divided by the total fossil-derived energy consumed by each system was calculated. This measure, known as the net energy ratio, is useful for assessing how much energy is generated for each unit of fossil fuel consumed. The other measure, the external energy ratio, is defined to be the energy delivered to the grid divided by the total non-feedstock energy to the power plant. That is, the energy contained in the coal and natural gas used at the fossil-based power plants is excluded. The external energy ratio assesses how much energy is generated for each unit of upstream energy consumed. Because the energy in the biomass is considered to be both generated and consumed within the boundaries of the system, the net energy ratio and external energy ratio will be the same for the biomass-only cases (biomass-fired IGCC and direct-fired biomass). In calculating the external energy ratio, we are essentially treating the coal and natural gas fed to the fossil power plants as renewable fuels, so that upstream energy consumption can be compared. Figure 1 shows the energy results for each case studied.

As expected, the biomass-only plants consume less energy overall, since the consumption of non-renewable coal and natural gas at the fossil plants results in net energy balances of less than one. The direct-fired biomass residue case delivers the most amount of electricity per unit of energy consumed. This is because the energy used to provide a usable residue biomass to the plant is fairly low. Despite its higher plant efficiency, the biomass IGCC plant has a lower net energy balance than the direct-fired plant because of the energy required to grow the biomass as a dedicated crop. Residue resource limitations, however, may necessitate the use of energy crops in the future. Cofiring biomass with coal slightly increases the energy ratios over those for the coal-only case, even though the plant efficiency was derated by 0.9 percentage points.

In calculating the external energy ratios, the feedstocks to the power plants were excluded, essentially treating all feedstocks as renewable. Because of the perception that biomass fuels are of lower quality than fossil fuels, it was expected that the external energy ratios for the fossil-based systems would be substantially higher than those of the biomass-based systems. The opposite is true, however, due to the large amount of energy that is consumed in upstream operations in the fossil-based systems. The total non-feedstock energy consumed by the systems is shown in Table 2. In the coal case, 35% of this energy is consumed in operations relating to flue-gas cleanup, including limestone procurement. Mining the coal consumes 25% of this energy, while transporting the coal is responsible for 32%. Greater than 97% of the upstream energy consumption related to the natural gas IGCC system is due to natural gas extraction and pipeline transport steps, including fugitive losses. Although upstream processes in the biomass systems also consume energy, shorter transportation distances and the fact that flue-gas desulfurization is not required, reduce the total energy burden.

Table 2: Non-feedstock Energy Consumption

System	Non-feedstock energy consumed (kJ/kWh)
Biomass-fired IGCC using hybrid poplar	231
Direct-fired biomass power plant using biomass residue	125
Average coal	702
Biomass / coal cofiring (15% by heat input)	614
Natural gas IGCC	1,718

Global Warming Potential

Figure 2 shows the net emissions of greenhouse gases, using the 100-year values from the Intergovernmental Panel on Climate Change. CO_2, CH_4, and N_2O were quantified for these studies. The biomass IGCC system has a much lower GWP than the fossil systems because of the absorption of CO_2 during the biomass growth cycle. Sensitivity analyses demonstrated that even moderate amounts of soil carbon sequestration (1,900 kg/ha/seven-year rotation) would result in the biomass IGCC system having a zero-net greenhouse gas balance. Sequestration amounts greater than this would result in a negative release of greenhouse gases, and a system that removes carbon from the atmosphere overall. The base case presented here assumes that there will be no net change in soil carbon, as actual gains and losses will be very site specific.

The direct-fired biomass system has a highly negative rate of greenhouse gas emissions because of the avoided methane generation associated with biomass decomposition that would have occurred had the residue not been used at the power plant. Based on current disposal practices, it was assumed that 46% of the residue biomass used in the direct-fired and cofiring cases would have been sent to a landfill and that the remainder would end up as mulch and other low-value products. Decomposition studies reported in the literature were used to determine that approximately 9% of the carbon in the biomass residue would end up as CH_4 were it not used at the power plant, while 61% would end up as CO_2. The remaining carbon is resistant to decomposition in the landfill, either due to inadequate growth conditions for the microbes or because of the protective nature of the lignin compounds. Had all of the residue biomass been decomposed aerobically, the CO2 produced would have been 1.85 kg/kg biomass. If the biomass residue was not used at the power plant, the decomposition pathways described above would have resulted in total greenhouse gas emissions of 2.48 kg CO_2-equivalent/kg biomass (1.117 kg CO_2 + .065 kg CH_4). The net difference is the reason for the negative greenhouse gas emissions associated with the direct-fired system.

The natural gas combined cycle has the lowest GWP of all fossil systems because of its higher efficiency, despite natural gas losses that increase net CH_4 emissions. Natural gas losses during extraction and delivery were assumed to be 1.4% of the gross amount extracted. Because of the potency of methane as a greenhouse gas, nearly one-quarter of the total GWP of this system is due to these losses.

Cofiring biomass with coal at 15% by heat input reduces the GWP of the average coal-fired power plant by 18%. The reduction in greenhouse gases is greater than the rate at which biomass is cofired because of the avoidance of methane emissions associated with decomposition that would have occurred had the biomass not been used at the power plant. Biomass disposal and decomposition emissions for this scenario are the same as those used in the direct-fired case.

Air Emissions

Emissions of particulates, SO_x, NO_x, CH_4, CO, and NMHCs are shown in Figure 3. Methane emissions are high for the natural gas case due to natural gas losses during extraction and delivery. The direct-fired biomass and coal/biomass cofiring cases have negative methane emissions, due to avoided decomposition processes (landfilling and mulching). CO and NMHCs are higher for the biomass case because of upstream diesel combustion during biomass growth and preparation. Cofiring reduces the coal system air emissions by approximately the rate of cofiring, with the exception of particulates, which are generated during biomass chipping and handling.

Resource Consumption

Figure 4 shows the total amount of non-renewable resources consumed by the systems. Limestone is used in significant quantities by the coal-fired power plants for flue-gas desulfurization. The natural gas IGCC plant consumes almost negligible quantities of resources, with the exception of the feedstock itself, including that lost during extraction and delivery.

Sensitivity Analysis

A sensitivity analysis was conducted on each system to determine which parameters had the most influence on the results and to pinpoint opportunities for reducing the environmental burden of the system. In general, parameters associated with increasing the system efficiency and reducing the fossil fuel usage had the largest effects. Additionally, for the biomass systems, variables associated with growing a dedicated feedstock and factors affecting how much CO_2 and CH_4 are avoided by using biomass residue significantly affected the GWP of the system. Overall, however, the sensitivity analyses demonstrated that the conclusions that can be drawn from these studies remain relatively constant as different parameters are varied.

SUMMARY

Completing several life cycle assessment studies has allowed us to determine where biomass power systems reduce the environmental burden associated with power generation. The key comparative results can be summarized as follows:

- The GWP of generating electricity using a dedicated energy crop in an IGCC system is 4.7% of that of an average U.S. coal power system.
- Cofiring residue biomass at 15% by heat input reduces the greenhouse gas emissions and net energy consumption of the average coal system by 18% and 12%, respectively.
- The life cycle energy consumption of the coal and natural gas systems are significantly lower than those of the biomass systems because of the consumption of non-renewable resources.
- Not counting the coal and natural gas consumed at the power plants in these systems, the net energy consumption is still lower than that of the biomass systems because of energy used in processes related to flue gas clean-up, transportation, and natural gas extraction and coal mining.
- The biomass systems produce very low levels of particulates, NO_x, and SO_x compared to the fossil systems.
- System methane emissions are negative when residue biomass is used because of avoided decomposition emissions.
- The biomass systems consume very small quantities of natural resources compared to the fossil systems.
- Other than natural gas, the natural gas IGCC consumes small amounts of resources.

These results demonstrate that overall, biomass power provides significant environmental benefits over conventional fossil-based power systems. In particular, biomass systems can significantly reduce the amount of greenhouse gases that are produced, per kWh of electricity generated. Additionally, because the biomass systems use renewable energy instead of non-renewable fossil fuels, they consume very small quantities of natural resources and have a positive net energy balance. Cofiring biomass with coal offers us an opportunity to reduce the environmental burdens associated with the coal-fired power systems that currently generate over half of the electricity in the United States. Finally, by reducing NOx, SOx, and particulates, biomass power can improve local air quality over coal-fired power generation.

Figure 1: Life Cycle Energy Balance

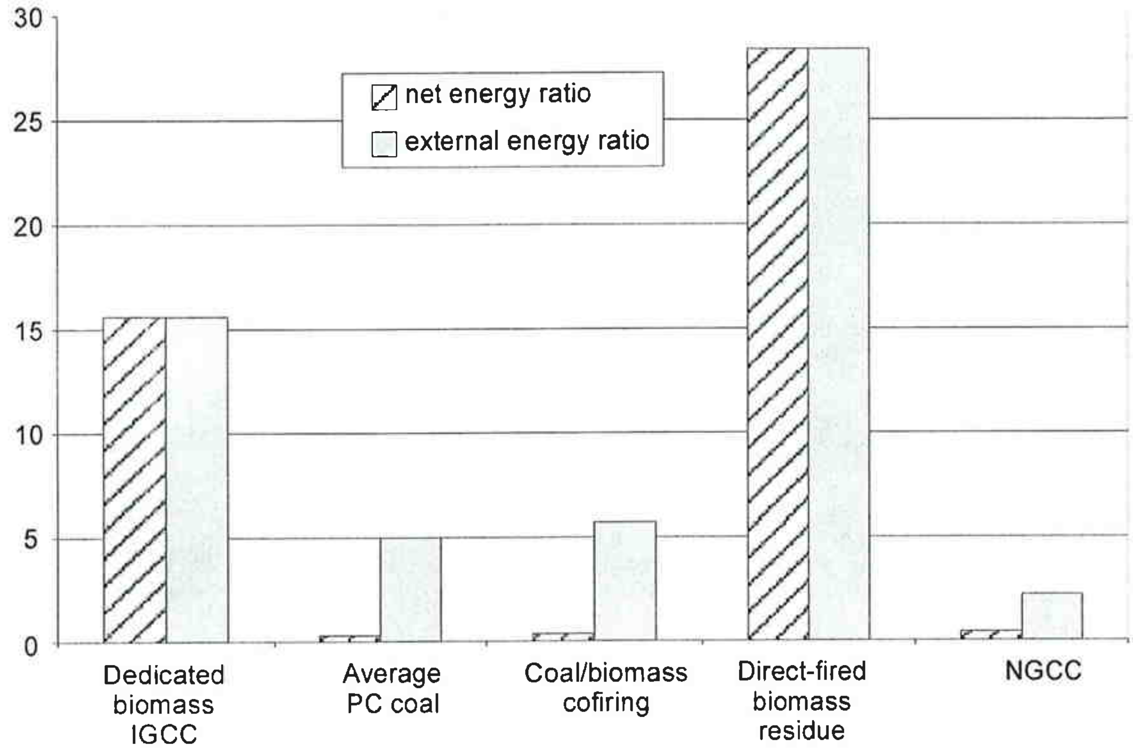


Figure 2: Net Life Cycle Greenhouse Gas Emissions

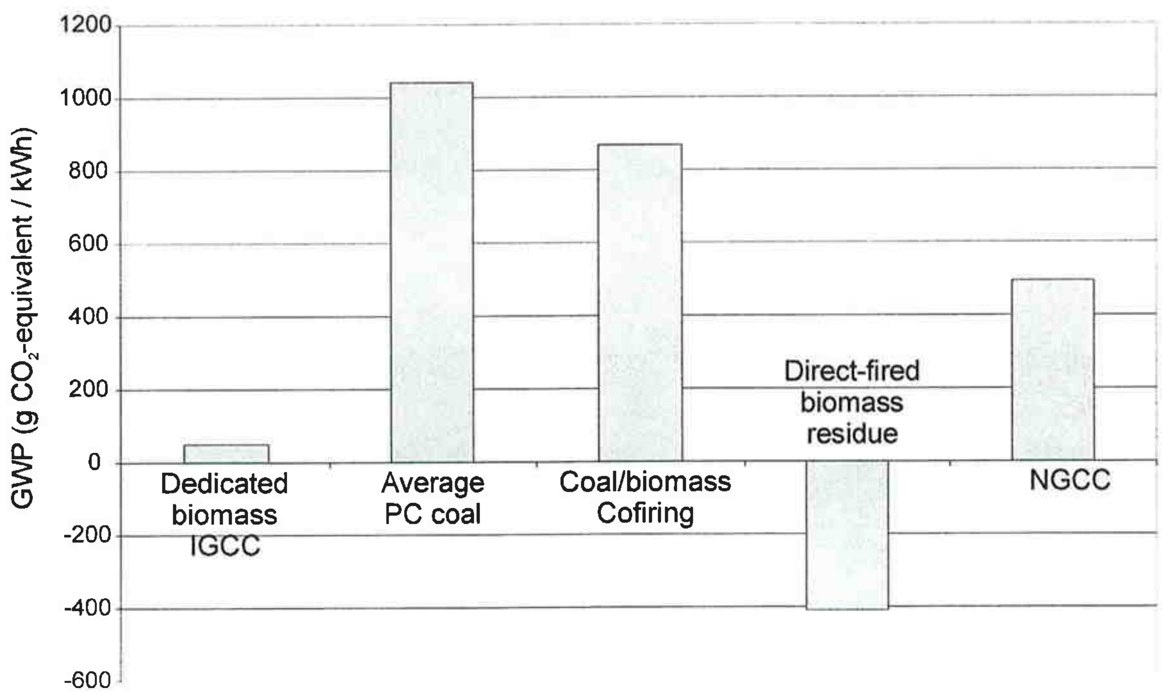


Figure 3: Other Air Emissions

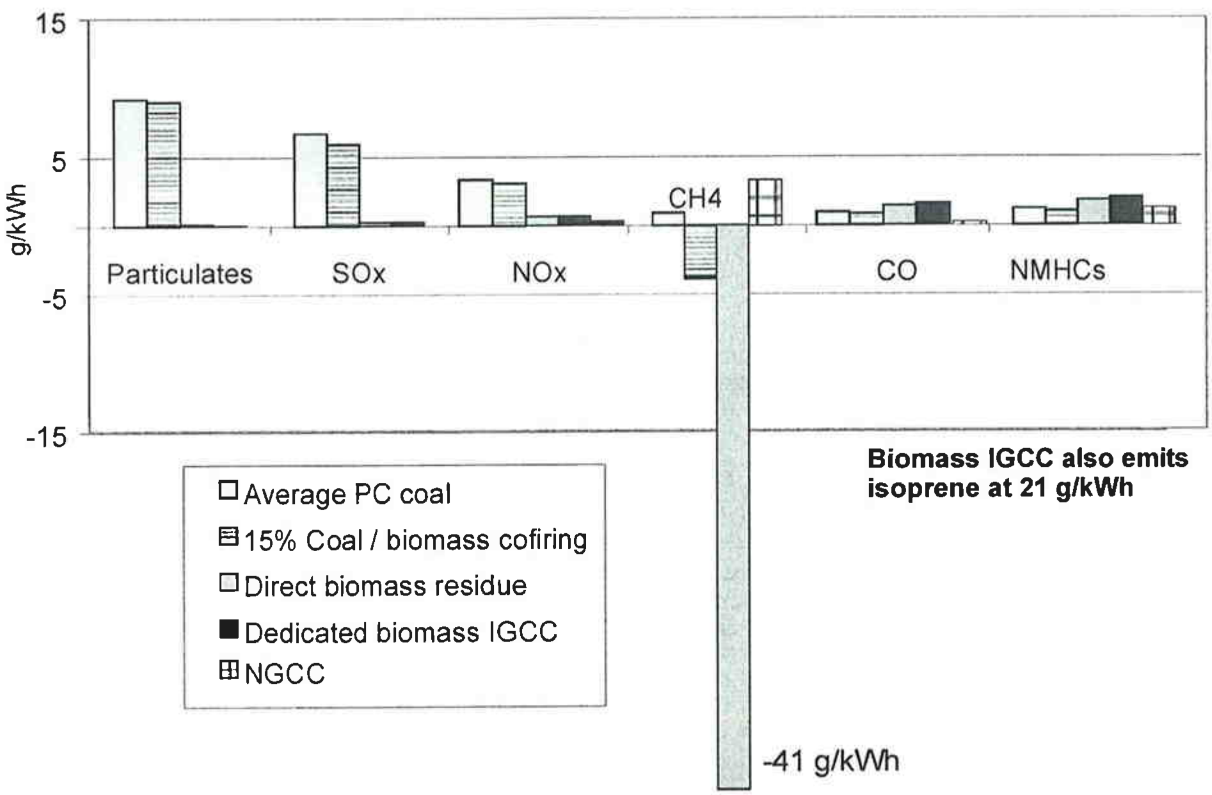
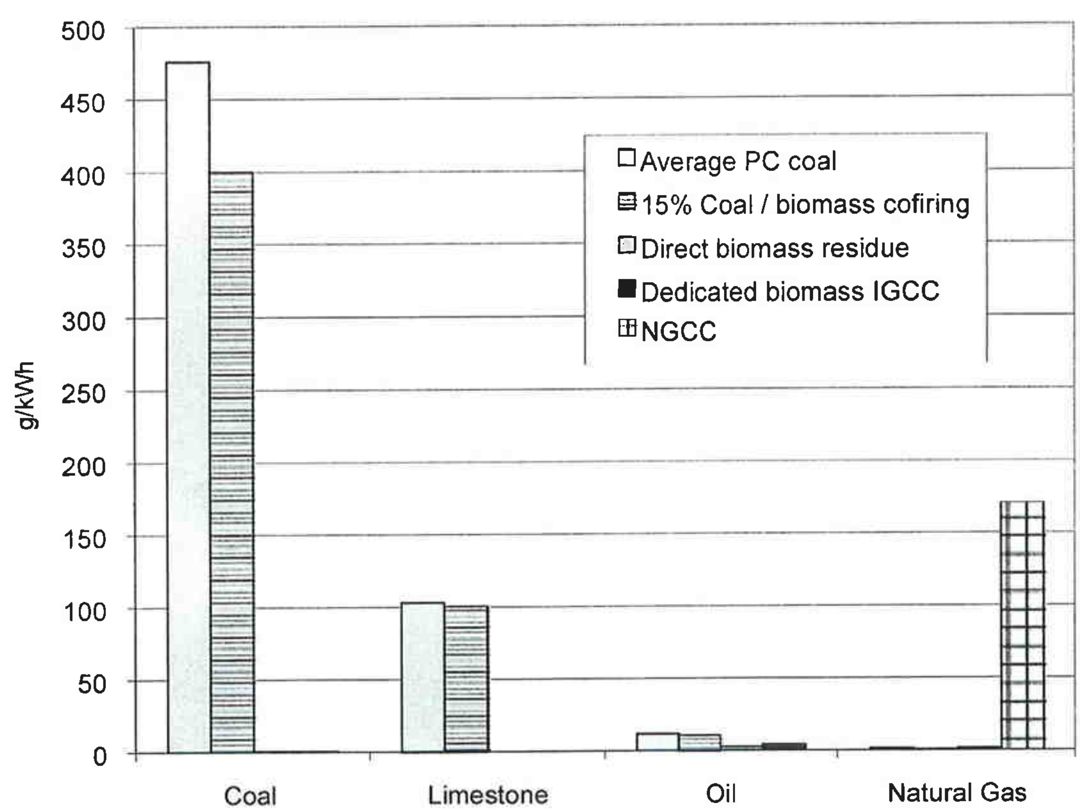


Figure 4: Resource Consumption



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