

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION MODIFICATION REQUEST

**ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT B COMBINED-CYCLE PROJECT**

Prepared for:



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BUREAU OF AIR REGULATION

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February 2008



Powering the Economy. Protecting the Environment.

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Air Construction/ Prevention of Significant Deterioration Permit Application

Submitted by:



JEA

City of Tallahassee
Your Own Utilities



The Reedy Creek
Improvement District

Prepared by:

ECT

Environmental Consulting & Technology, Inc.
ECT No. 080019-0100

Sargent & Lundy

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

The Florida Municipal Power Agency (FMPA), JEA, Reedy Creek Improvement District (RCID), and the City of Tallahassee (collectively referred to as the Participating Utilities) plan to construct, own, and operate a nominal 800-MW advanced supercritical pulverized coal electric generating unit and associated facilities, including state-of-the-art emission control systems. The Taylor Energy Center (TEC) will be located on an approximately 2,997-acre site located in east-central Taylor County approximately 5 miles southeast of the city of Perry.

The main plant facilities and systems for the TEC Project will include a supercritical boiler, steam turbine generator, mechanical draft cooling tower, process and potable water supply systems, wastewater treatment systems (including a zero discharge crystallizer), material handling systems, rail delivery loop, fuel and byproduct handling and storage systems, main boiler air quality control systems, electrical interconnection facilities, and other balance-of-plant systems and equipment. The facilities will include a 550-foot (ft) main boiler exhaust stack; ultra low sulfur diesel (ULSD) fuel oil-fired auxiliary boiler for use during startups; diesel-fired emergency firewater pump and fire protection system; ground water supply well system; administration building; and various maintenance and equipment storage warehouses.

Fuel flexibility needed to maintain competitively priced sources of coal is an important TEC design criterion. The main boiler will be designed to fire 100-percent bituminous coal, blends of bituminous and subbituminous coals, and blends of bituminous or subbituminous coal with petcoke. The maximum amount of petcoke blended with coal will be approximately 30 percent by weight. ULSD fuel oil will be used as the main boiler startup fuel. Emissions from the boiler will be controlled using best available control technologies (BACT). Proposed BACT control technologies include:

- Low-NO_x burners and overfire air to minimize the formation of NO_x.
- SCR for NO_x control and mercury removal enhancement.
- Fabric filter for control of particulate matter and mercury.

- Wet limestone, forced oxidation FGD for SO₂, mercury, and HAP control.
- WESP for sulfuric acid mist, condensable fine particulate, and mercury control.

As indicated, in addition to its primary function, each air emission control device listed will have a cobenefit of removing mercury and/or contributing to the removal of mercury. In addition, the TEC Project will be designed with specific mercury control technology(ies) (i.e., fuel and/or FGD additives) to further minimize mercury emissions.

Operation of the proposed TEC Project will result in airborne emissions. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This submittal, including the required permit application forms and supporting documentation included in the appendices, constitutes the Participating Utilities application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, *et. seq.*, F.A.C.

The TEC Project will have potential emissions greater than 100 tons per year of a PSD pollutant and is one of the named major stationary source categories (i.e., fossil fuel-fired steam electric plants of more than 250 MMBtu/hr) listed in Section 169 of the CAA and Rule 62-210.200(193)(a)1., F.A.C. Accordingly, the TEC Project will be classified as a *major facility* subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.

- Section 3.0 describes the NSR requirements and discusses applicability of these requirements to the proposed project.
- Section 4.0 describes the applicable state and federal emission standards.
- Section 5.0 provides an analysis of best available control technology (BACT).
- Sections 6.0 (Dispersion Modeling Methodology) and 7.0 (Dispersion Modeling Results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of the project and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 provides an assessment of impacts on Class I areas located within 300 km of the project site.

Appendices A and B provide emission rate calculations and the FDEP Application for Air Permit—Long Form, respectively. All dispersion modeling input and output files for the ambient impact analyses are provided in Appendix C. An assessment of the weather conditions associated with Class I area natural visibility impairment is provided in Appendix D.

1.2 SUMMARY

The primary source of emissions from the TEC Project will result from the combustion of solid fuels in the main boiler. Emissions from the main boiler comprise 99.5 percent of total estimated TEC Project annual emissions. Principal air contaminants that will be emitted from the main boiler stack include NO_x, SO₂, CO, VOC, PM/PM₁₀, HF, HCl, and H₂SO₄. The main boiler will also emit trace amounts of metallic and organic compounds. Ancillary TEC Project emission sources include an auxiliary boiler, mechanical draft cooling tower, emergency generator diesel engine, emergency fire water pump diesel engine, and material (solid fuels, limestone, and combustion byproduct) storage and handling systems.

The planned TEC construction start date is the fourth quarter of 2008 with initial operation planned for the fourth quarter of 2012.

Based on an evaluation of anticipated worst-case annual operating scenarios, TEC will have the potential to emit 1,653 tpy of nitrogen oxides (NO_x), 4,925 tpy of carbon monoxide (CO), 539 tpy of particulate matter (filterable), 820 tpy of particulate matter less than or equal to 10 micrometers (PM₁₀ – filterable and condensable), 1,310 tpy of sulfur dioxide (SO₂), 119 tpy of volatile organic compounds (VOCs), 0.13 tpy of lead, 0.029 tpy of mercury, 15 tpy of total fluorides, and 131 tpy of sulfuric acid (H₂SO₄). Based on these potential annual emission rates, NO_x, CO, PM/PM₁₀, SO₂, VOC, total fluorides, and H₂SO₄ mist emissions are subject to PSD review.

As presented herein, the analyses required for this permit application have resulted in the following conclusions. Since the primary TEC emission source is the supercritical PC main boiler, these conclusions primarily address this emission unit.

- Low-NO_x burners, overfire air, and selective catalytic reduction (SCR) represent BACT for NO_x. The proposed NO_x BACT emission limit of 0.05 lb/MMBtu (30-day rolling average) represents the lowest emission rate proposed for any pulverized coal plant, and lower than the BACT limits in any permitted pulverized coal utility boiler.
- Wet limestone forced oxidation flue gas desulfurization (FGD) represents BACT for SO₂. The proposed SO₂ BACT emission limit of 0.04 lb/MMBtu (30-day rolling average) represents the lowest remission rate proposed for any pulverized coal plant, and lower than the BACT limits in any permitted pulverized coal utility boiler. Use of ultra low sulfur diesel (ULSD) fuel oil represents SO₂ BACT for the oil-fired TEC combustion sources.
- Good combustion design and operation represent BACT for CO and VOC. Boiler combustion design and operation requires a balancing of the competing goals to minimize the formation of both NO_x and CO/VOC. The proposed CO BACT emission limits of 0.15 lb/MMBtu (all fuels, 30-day rolling average) and 0.13 lb/MMBtu (coal only, stack test), and VOC BACT emis-

sion limit of 0.0036 lb/MMBtu reflect this balance and the aggressive NO_x BACT emission limit proposed for TEC.

- Wet FGD and wet electrostatic precipitator (WESP) technology represent BACT for H₂SO₄ mist and total fluorides (HF). The test method used to measure H₂SO₄ emission rates (EPA Test Method 8) has proven to be problematic on coal-fired boilers. The proposed H₂SO₄ mist and HF BACT emission limits of 0.004 and 0.00047 lb/MMBtu, respectively, are based on the application of the most efficient control technology available and test method constraints.
- Fabric filter, wet FGD, and WESP represent BACT for PM (filterable) and PM₁₀ (filterable and condensable). TEC will employ a range of fuels and therefore differs from mine-mouth projects which will have little variability in fuel characteristics. The proposed PM (filterable) and PM₁₀ (filterable and condensable) BACT emission limits of 0.013 and 0.025 lb/MMBtu, respectively, reflect the expected performance of the most efficient control technology available. Water suppression, enclosure, and fabric filter technology will be used to control PM/PM₁₀ emission from the material handling and storage activities. The mechanical draft cooling tower will employ high efficiency drift eliminators to achieve a drift loss rate of no more than 0.0005-percent of the cooling tower recirculating water flow.
- TEC is projected to emit NO_x, PM₁₀, SO₂, HF, CO, and VOC in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants with the exception of PM₁₀ and VOC. Preconstruction monitoring for ozone is required if potential VOC emissions from a project subject to PSD review exceed 100 tpy. Accordingly, TEC qualifies for the Rule 62-212.400(3)(e), F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants except PM₁₀ and VOC. Current (2002 – 2006) quality-assured ambient air data collected at the FDEP's ozone monitoring sites in Tallahassee, Leon County, and PM₁₀ monitoring station in Hamilton County were used to satisfy the PSD preconstruction ambient air monitoring requirements for ozone and PM₁₀.

- With the exception of PM₁₀, the ambient impact analysis demonstrates that project impacts will be below the PSD Class II significant impact levels defined in Rule 62-210.200(278), F.A.C. Accordingly, a multisource cumulative assessment of national ambient air quality standards (NAAQS) attainment and PSD Class II increment consumption was only required for PM₁₀. The cumulative modeling analysis demonstrates that TEC and off-site emission source total PM₁₀ impacts will be below the NAAQS and PSD Class II increments.
- Class I areas located within 300 km of TEC include the Okefenokee and Wolf Island National Wilderness Areas (NWAs) in Georgia, and the Bradwell Bay, St. Marks, and Chassahowitzka NWAs in Florida. Assessments of PSD Class I increment and air quality related values (sulfur and nitrogen deposition, and visibility) were conducted for each of these five Class I areas.
- With the exception of SO₂, the ambient impact analysis demonstrates that project impacts will be below the EPA proposed PSD Class I significant impact levels for all Class I areas evaluated. Accordingly, a multisource cumulative assessment of PSD Class I increment consumption was only required for SO₂. The cumulative modeling analysis demonstrates that TEC and off-site emission source total SO₂ impacts will be below the PSD Class I increments.
- The analyses of PSD Class I area air quality related values indicates that TEC impacts will be below levels that are detrimental to soils and vegetation and will not impair visibility.
- Based on refined dispersion modeling, TEC will not cause nor contribute to an exceedance of any NAAQS, Florida ambient air quality standards (AAQS), or PSD increment for Class I or Class II areas.

2.0 PROJECT DESCRIPTION

2.1 PROJECT LOCATION, AREA MAP, AND PLOT PLAN

The approximate 2,997-acre TEC Site is located in east-central Taylor County 5 miles southeast of the city of Perry. The Site is generally bordered by U.S. Highway 27 (U.S. 27) on the north, the Fenholloway River on the northwest and west, and county-maintained Connell Grade on the south. Most of the Site and surrounding properties are currently in active planted pine silviculture use. The Site contains numerous isolated forested wetlands that have been historically impacted by timbering and ground water draw-down. The nearest residential area to the Site contains three single-family residences located west of the Fenholloway River. The Buckeye Florida, L.P. (Buckeye), cellulose plant, which is the largest industrial land use in Taylor County, is located approximately 1.5 miles west of the Site.

Figure 2-1 shows the general location of the TEC Site within the state of Florida. Figure 2-2 depicts the site boundary and proposed layout of the new facilities as they are arranged on the site. Figure 2-3 provides a more detailed layout of the power block, air quality control system, and coal, limestone and byproduct handling facilities. A conceptual rendering of the major TEC Project facilities is presented in Figure 2-4.

The main power block area, which includes the boiler and steam turbine, will be located at the approximate center of the site. The new switchyard will be located north of the turbine building, with the transmission lines exiting the plant site to the west. The air quality control system (AQCS) equipment will be located south of the boiler. The stack will be located south of the AQCS. The mechanical draft cooling tower makeup water treatment building and wastewater holding ponds will be located just west of the power block.

Coal and petcoke storage, both active and inactive, will be located west of the cooling tower. A rail loop will surround the solid fuel storage area. Trains delivering solid fuel will enter and exit the site at the northwest corner.

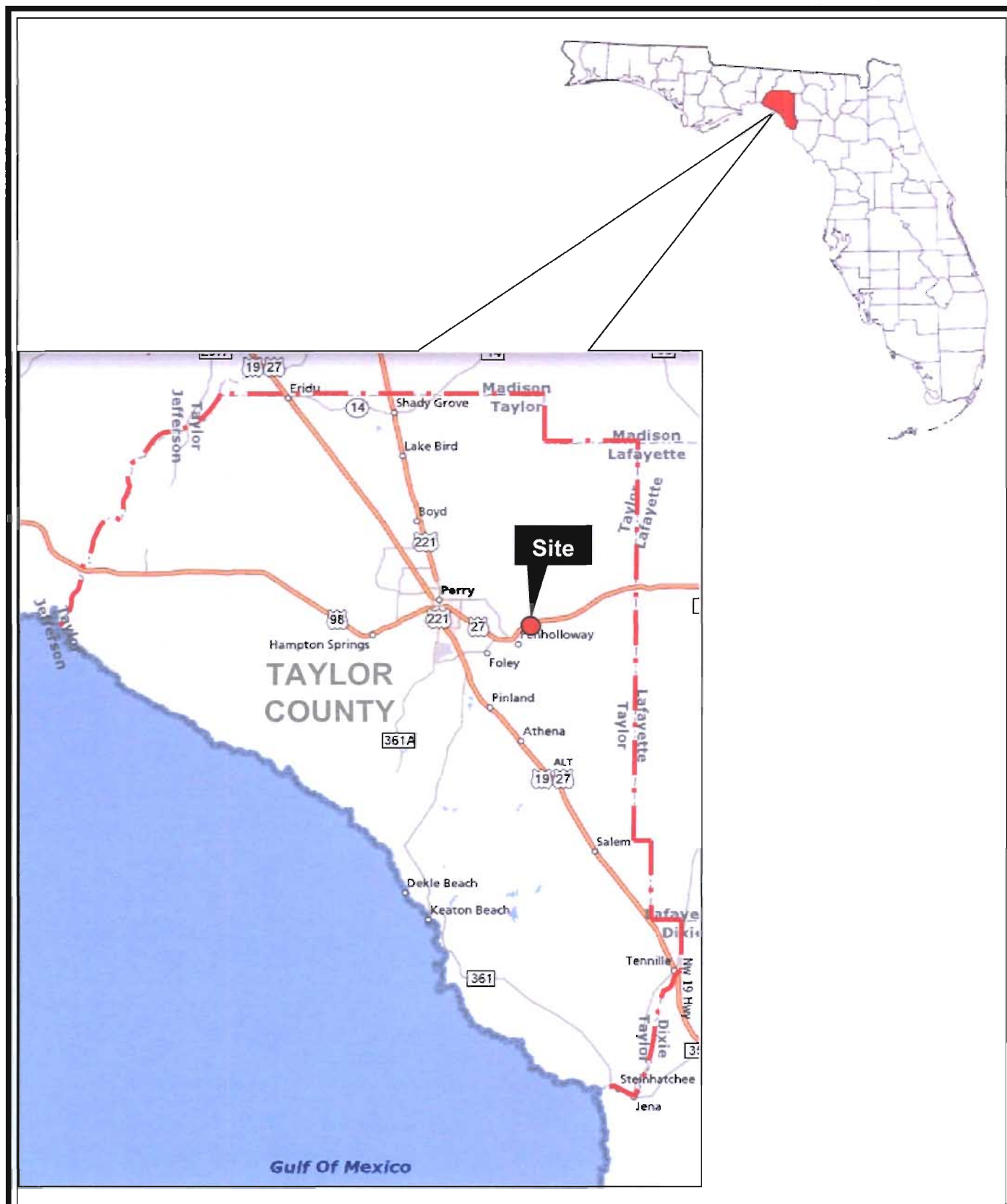


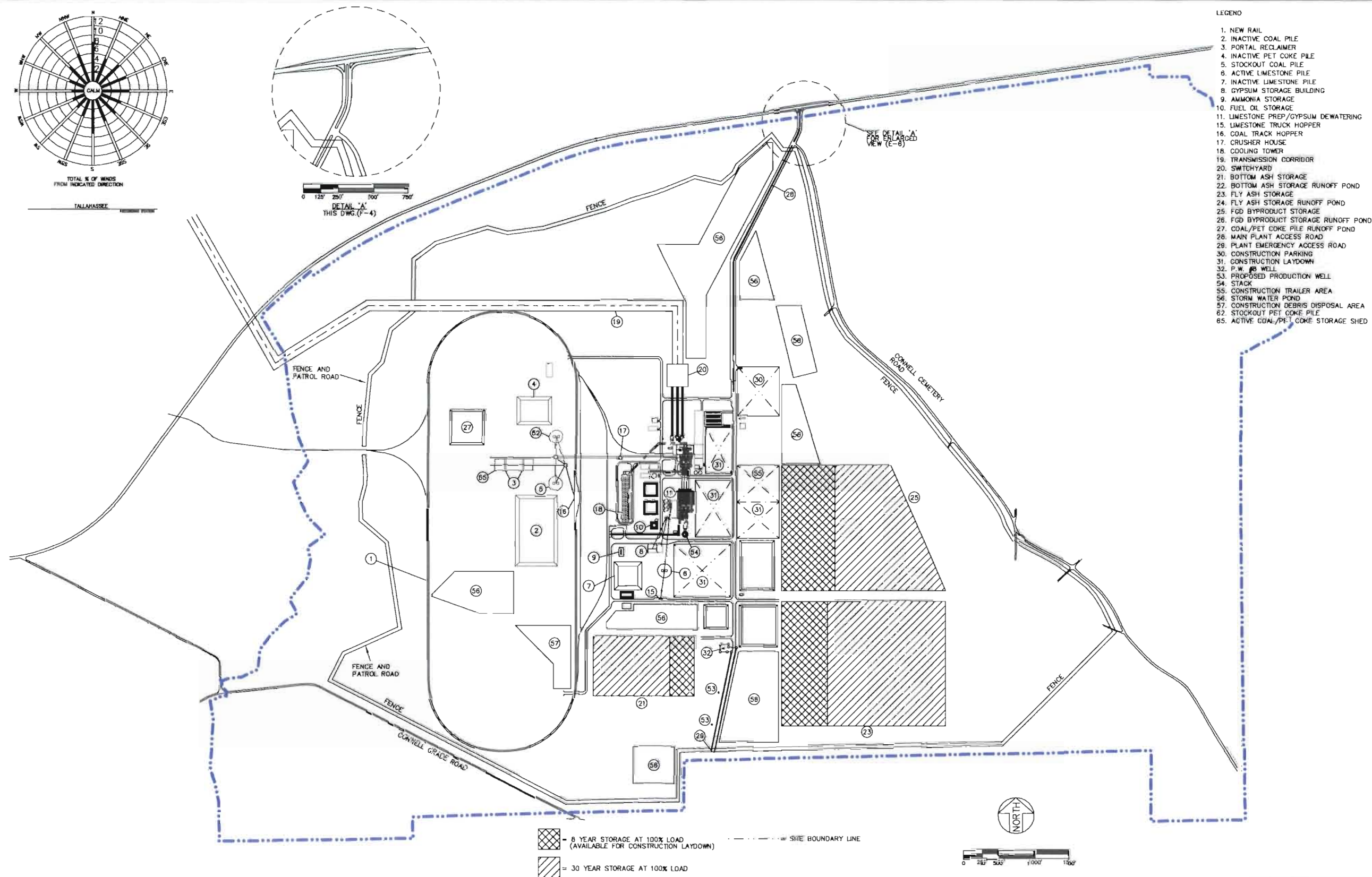
FIGURE 2-1.

TEC SITE LOCATION

Source: ECT, 2006.



Powering the Economy. Protecting the Environment.



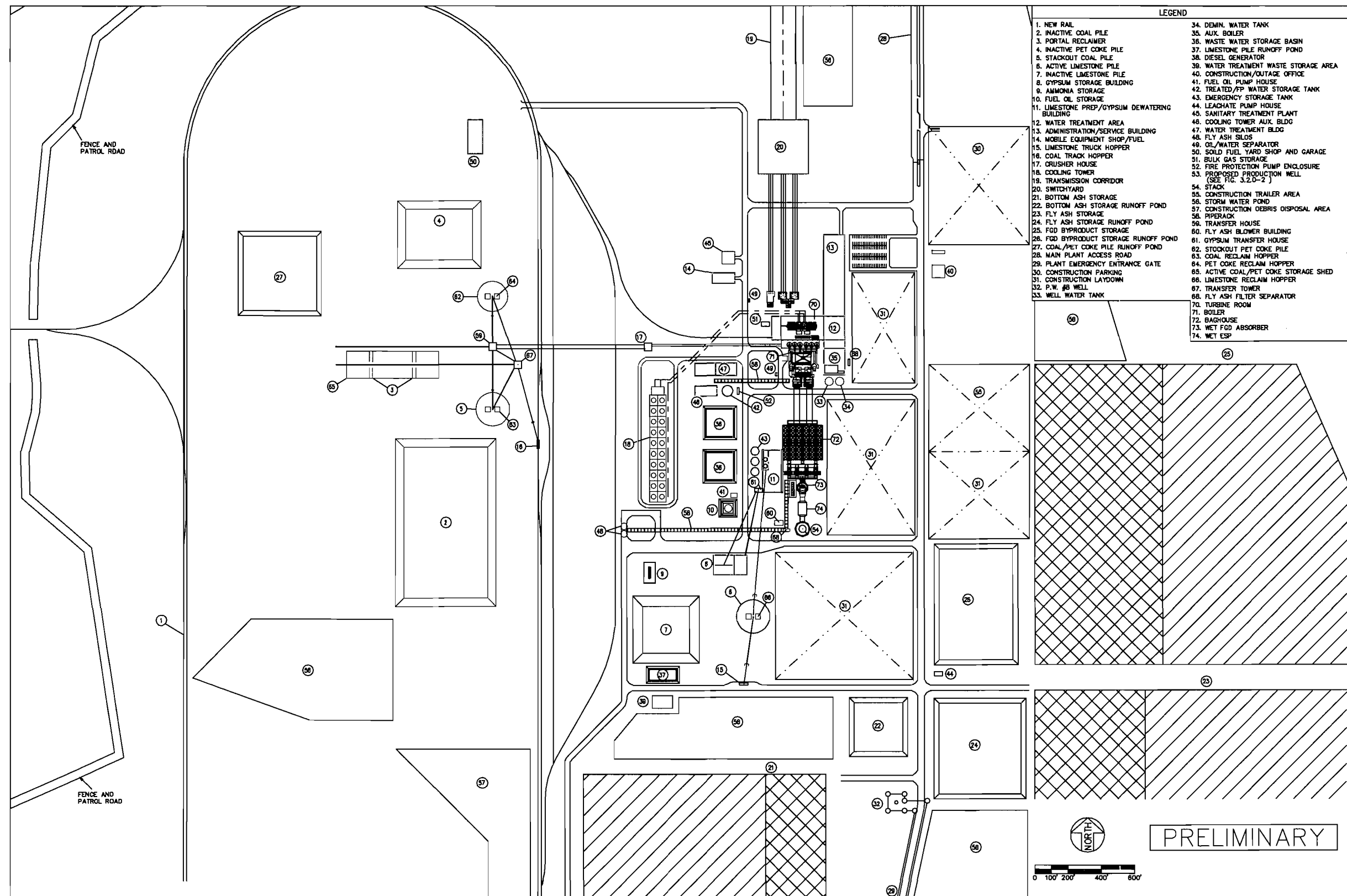


FIGURE 2-3.
DETAILED SITE LAYOUT

Source: Sargent & Lundy, 2006.

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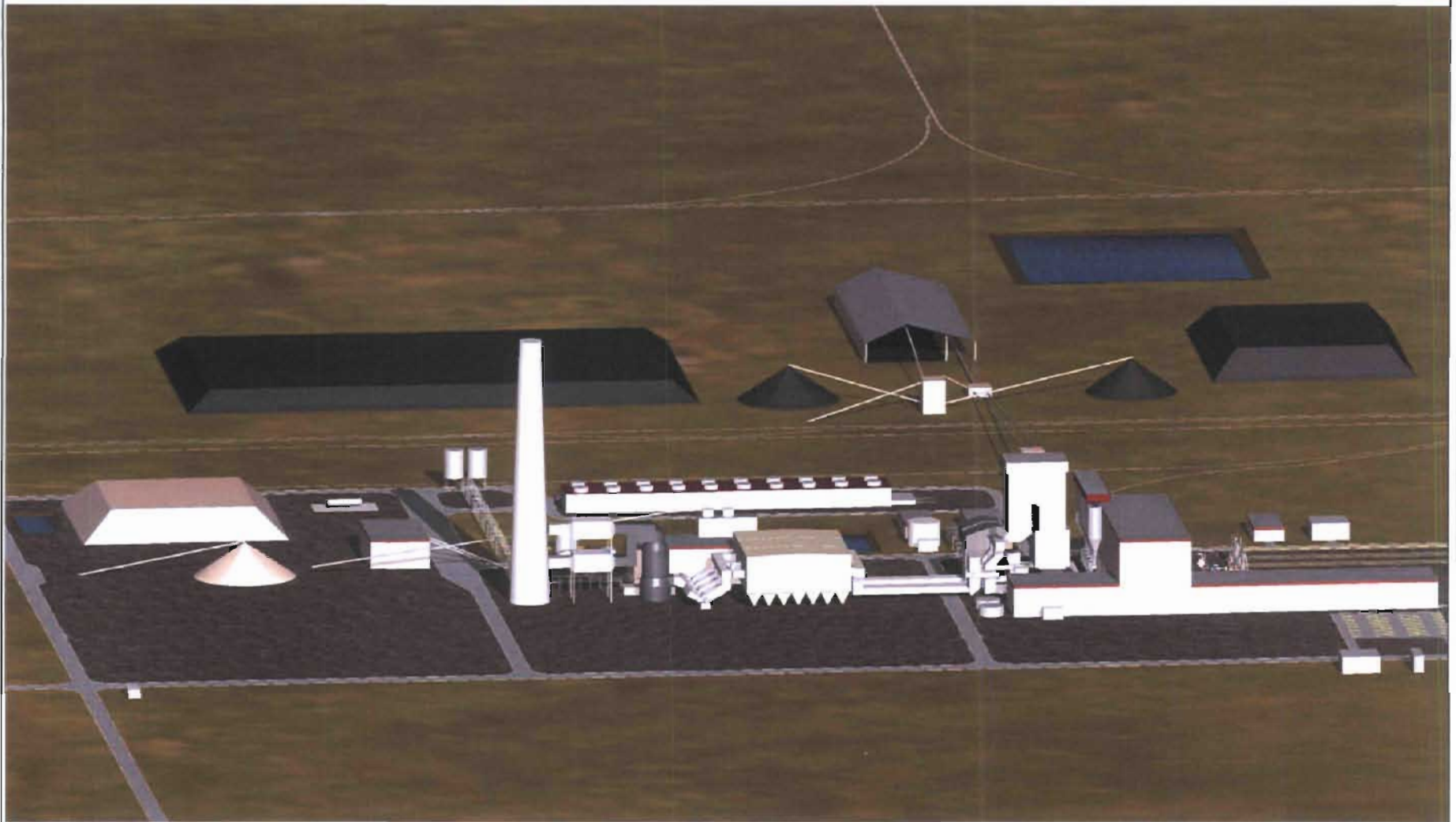


FIGURE 2-4.

CONCEPTUAL RENDERING OF TEC

Source: S&L, 2006.

Limestone storage, flue gas desulfurization (FGD) system reagent preparation and gypsum dewatering building, and the FGD gypsum byproduct stock-out building will be located adjacent to and southwest of the AQCS. Byproduct storage areas and leachate collection ponds will be located south and east of the power block.

2.2 PROJECT FUELS

Discussions of the solid and liquid fuels planned for the TEC project are provided in the following subsections.

2.2.1 SOLID FUELS

A key design criterion for the TEC Project is fuel flexibility to be able to take full advantage of competitive fuel pricing and availability opportunities and transportation options in the future marketplace to provide low cost, reliable electricity to their Customers. Therefore, the TEC main boiler, fuel delivery and handling, and other facilities have been designed to be capable of using a wide variety of coals, coal blends, and coal/petcoke blends. This fuel flexibility will allow for solid fuels to be sourced from multiple, regional locations with alternative transportation options, thus increasing the overall reliability of the fuel supply to TEC.

To achieve these fuel flexibility objectives, a wide array of coals with varying heating values and sulfur contents were investigated for use at TEC. The coals investigated included Northern and Central Appalachian bituminous coal, Illinois basin bituminous coal, Latin American bituminous coal, and Powder River Basin (PRB) subbituminous coal. Petcoke available from Gulf Coast and Caribbean refineries was also investigated as a supplemental fuel that could be blended with coal. Petcoke is a residual byproduct of the oil refining process and has a high energy value and low ash content compared to coal. Depending on market conditions, petcoke can be a cost-effective substitute for coal thereby helping to reduce fuel costs. However, petcoke has a higher sulfur content and must be blended in limited amounts with lower sulfur coals. The proposed unit design will be capable of handling coal/petcoke blends containing up to 30-percent petcoke by weight.

The fuel selection investigation included consideration of long-term projected fuel prices and availability, fuel transportation and handling costs, uncontrolled SO₂ emissions, and FGD system reagent costs. The purpose of the investigation was to establish plant fuel flexibility design criteria by identifying alternative sources of competitively priced coals and coal blends capable of meeting stringent emission limitations.

The TEC fuel selection investigation determined that blends of petcoke with Latin American, PRB, and Central Appalachian coals are the most cost-competitive fuels among the range of coals and coal blends evaluated. TEC will be designed such that the petcoke/coal blend will achieve an uncontrolled sulfur dioxide (SO₂) emission of no more than 3.46 pounds per million British thermal units (lb/MMBtu). The design uncontrolled SO₂ emission rate of 3.46 lb/MMBtu is based on the expected achievable day-to-day SO₂ removal capability of the latest generation of wet limestone FGD systems and the best available control technology (BACT) SO₂ emission limits proposed for the TEC main boiler.

Based on the results of the fuel selection investigation, ultimate and trace mineral analyses were obtained for typical coals from specific mines in the coal regions most likely to be considered as sources for contracted coal supplies for TEC. An *average* constituent analysis was developed for each regional coal and for petcoke. Table 2-1 presents these analyses.

Since a unit designed for fuel flexibility may fire a wide range of coals, coal blends, and coal/petcoke blends over its operating life, design criteria for the boiler, selective catalytic reduction (SCR), bottom ash system, particulate control equipment, FGD system, wet electrostatic precipitator (WESP), and material handling systems must identify the maximum or *worst case* analysis of fuel constituents among the range of potential fuels. Therefore, a design constituent analysis was developed for each regional coal and for petcoke (i.e., high sulfur content combined with low heating value). Table 2-2 summarizes the design constituent analyses for each regional coal and for petcoke.

Table 2-1. Average Constituent Analysis of Coals and Petcoke

	Central Appalachian	PRB	Latin American	Petcoke
Carbon	72.33	51.83	69.50	79.93
Sulfur	1.13	0.24	0.66	6.04
Oxygen	3.53	12.40	8.39	0.04
Hydrogen	4.68	3.41	4.63	3.48
Nitrogen	1.27	0.63	1.25	2.12
Chlorine	0.16	0.01	0.04	0.01
Ash	11.33	4.85	6.87	0.47
Moisture	5.57	26.82	8.66	7.93
Total	100	100	100	100
Gross HHV (Btu/lb)	13,359	8,830	12,220	14,000
SO ₂ (lb/MMBtu)	1.69	0.54	1.08	8.63

Note: HHV = higher heating value.

Btu/lb = British thermal unit per pound.

Units are percent by weight unless otherwise noted.

Source: Compiled by Sargent & Lundy from data provided by Hill & Associates *et al.*

Table 2-2. Design Constituent Analysis of Coals and Petcoke

	Central Appalachian	PRB	Latin American	Petcoke
Carbon	68.31	50.63	65.79	78.34
Sulfur	1.47	0.35	0.75	6.50
Oxygen	3.33	12.11	7.95	0.04
Hydrogen	4.42	3.33	4.38	3.41
Nitrogen	1.20	0.62	1.18	2.08
Chlorine	0.20	0.04	0.04	0.21
Ash	14.04	5.46	8.50	0.73
Moisture	7.03	27.40	11.40	8.74
Total	100	100	100	100
Gross HHV (Btu/lb)	12,258	8,800	11,055	13,809
SO ₂ (lb/MMBtu)	2.40	0.80	1.36	9.41

Note: HHV = higher heating value.

Btu/lb = British thermal unit per pound.

Units are percent by weight unless otherwise noted.

Source: Compiled by Sargent & Lundy from data provided by Hill & Associates *et al.*

Since the fuel selection investigation determined that the most cost-competitive fuels are likely to be blends of petcoke with lower sulfur Latin American, PRB, and Central Appalachian coals, the constituent values presented in Table 2-2 were used to develop a design constituent analysis for each of these blends corresponding to 3.46 lb/MMBtu maximum uncontrolled SO₂ emissions. Table 2-3 presents these analyses.

The quantity of solid fuel required at TEC will vary depending on the fuel characteristics and the demand for electric generation. At any moment of unit operation, the fuel firing rate is set by the boiler heat input requirement, boiler efficiency, and fuel higher heating value. The maximum boiler heat input (British thermal units per hour [Btu/hr]) corresponds to the maximum operating boiler load (i.e., the condition of maximum steam generation). The fuel firing rate (pound per hour [lb/hr]) required to produce the maximum boiler heat input is determined by dividing the boiler heat input by the product of the boiler efficiency (for the specific fuel being fired) and the fuel higher heating value (British thermal unit per pound [Btu/lb]). The maximum annual quantity of fuel required is the maximum hourly fuel firing rate times 8,760 hours (the number of hours in a year). Table 2-4 summarizes maximum annual quantities of fuel required by TEC over the range of potential fuels.

2.2.2 LIQUID FUELS

Ultra low sulfur diesel (ULSD) fuel oil will be used as the main boiler startup fuel. ULSD will be fired during initial warm-up and to support coal ignition. After establishment of stable coal combustion, the ignition burners will be shut down. ULSD will also be fired in the auxiliary boiler. In addition, the emergency generator and the emergency firewater pump will be designed to fire ULSD. Table 2-5 provides a typical analysis of ULSD fuel.

The quantity of ULSD fired at TEC will depend on the number of cold boiler starts and the annual hours of operation of the auxiliary boiler, emergency generator, and backup firewater pump. The average heat input to the boiler from igniters and warm-up burners during a typical 20-hour cold startup is equivalent to approximately 20 percent of the maximum heat input (i.e., 1,495 million British thermal units per hour [MMBtu/hr]). The main boiler could have at least one cold start each year following its scheduled

Table 2-3. Design Constituent Analysis of Coal/Petcoke Blends

	Central Appalachian with Petcoke	PRB with Petcoke	Latin American with Petcoke
Petcoke	13.70	22.20	22.10
Carbon	69.68	56.78	68.56
Sulfur*	2.16	1.72	2.02
Oxygen	2.88	9.43	6.20
Hydrogen	4.28	3.35	4.17
Nitrogen	1.32	0.94	1.38
Chlorine	0.20	0.07	0.08
Ash	12.22	4.41	6.78
Moisture	7.26	23.26	10.81
Total	100	100	100
Gross HHV (Btu/lb)	12,470	9,912	11,664
SO ₂ (lb/MMBtu)	3.46	3.46	3.46

Note: HHV = higher heating value.

Btu/lb = British thermal unit per pound.

Units are percent by weight unless otherwise noted.

*Maximum sulfur content will vary with coal/petcoke blend heat content but will not exceed 3.46 lb/MMBtu SO₂.

Source: Compiled by Sargent & Lundy from data provided by Hill & Associates *et al.*

Table 2-4. Quantities of Solid Fuel Fired (Based on Design Constituents)

	Unit	Central Ap- palachian with Petcoke	PRB with Petcoke	Latin American with Petcoke	Central Appalachian	Latin American
Maximum rate of design fuel fired	ton/hr	293.5	377.1	316.4	299.1	336.1
Maximum annual quantity of fuel	tpy	2,570,808	3,303,079	2,771,971	2,619,706	2,943,943

Note: ton/hr = tons per hour.
tpy = tons per year

Source: S&L, 2007.

Table 2-5. Typical ULSD Fuel Oil Analysis

Component	ULSD
Carbon	85.0
Hydrogen	14.8
Oxygen	0.5
Nitrogen	0.5
Sulfur	<0.0015
Ash	0.01
Heat content (HHV) (Btu/gal)	137,000

Note: HHV = higher heating value.
 Btu/gal = British thermal unit per gallon.
 Units are percent by volume unless otherwise noted.

Sources: S&L, 2007.
 ECT, 2007.

maintenance outage and may have up to 11 additional starts annually due to brief unscheduled maintenance outages, some of which could also result in cold restarts of the unit based on the duration of the outage.

The auxiliary boiler will have a maximum heat input of approximately 375 MMBtu/hr. It is anticipated that the auxiliary boiler will operate a maximum of 876 hours per year (hr/yr).

The emergency generator and emergency firewater pump diesel engines will have maximum heat inputs of approximately 18.25 and 3.33 MMBtu/hr, respectively. Routine testing of the emergency generator and emergency firewater pump engines will take place approximately once each month for an 8-hour maximum run. This will result in approximately 96 hr/yr of operation for each engine, excluding operation during emergency conditions.

Table 2-6 summarizes the estimated, potential annual ULSD requirements at TEC based on the liquid fuel characteristics presented in Table 2-5.

2.3 PROJECT DESCRIPTION AND FLOW DIAGRAMS

The main onsite plant facilities and systems for the TEC Project will include a supercritical boiler, main boiler air quality control systems, steam turbine generator, mechanical draft cooling tower, process and potable water supply systems, wastewater treatment systems (including a zero discharge crystallizer), rail delivery loop, fuel and combustion by-product material handling and storage systems, electrical interconnection facilities, and other balance-of-plant systems and equipment. The onsite facilities will include a 550-foot (ft) main boiler exhaust stack; ULSD fuel oil-fired auxiliary boiler for use during startups; diesel-fired emergency firewater pump and fire protection system; ULSD storage tanks; ground water supply well system; administration building; and various maintenance and equipment storage warehouses. Major components of the TEC Project are described in the following sections.

Table 2-6. Quantity of ULSD Fuel Fired

Unit	Main Boiler Igniters	Auxiliary Boiler	Emergency Generator	Emergency Firewater Pump
MMBtu/hr	1,495	375	18.25	3.33
hr/yr	Varies	876	96*	96*
gal/yr	3,000,000	2,218,500	12,800	2,300

Note: gal/yr = gallons per year.

*Excluding operation during emergency conditions.

Source: S&L, 2007.

2.3.1 MAIN BOILER

Pulverized coal-fired boilers are generally classified as *subcritical* and *supercritical* boilers. The term *supercritical* refers to the main steam turbine throttle operating temperature and pressure. Modern subcritical units have a maximum turbine throttle pressure of approximately 2,520 pounds per square inch gauge (psig), while supercritical cycles have turbine throttle pressures above 3,300 psig. When water is heated to a temperature and a pressure above 705 degrees Fahrenheit (°F) and 3,208 pounds per square inch absolute (psia) (the critical point of water), it does not boil to produce a two-phase mixture of water and steam, but instead experiences a continuous transition from water-like to steam-like characteristics. Thus, the throttle pressure and temperature of a subcritical cycle is limited by the properties of water, whereas the throttle pressure and temperature of a supercritical cycle is limited by the capabilities of the materials used to construct the boiler, piping, and turbine.

The TEC boiler is being designed as a balanced draft, once through, supercritical boiler capable of developing main steam turbine throttle pressures in the range of 3,600 to 3,800 psig and temperatures in the range of 1,050 to 1,100°F. The boiler will have a re-heat steam temperature at the inlet of the intermediate pressure turbine of approximately 1,100 to 1,150°F. Boilers with main steam turbine throttle pressures and temperatures above the critical point of water are referred to as supercritical boilers. The higher pressures associated with supercritical cycles result in higher turbine efficiencies. This difference in efficiency results in a heat rate (Btu heat input per MW energy output) improvement of approximately 2 to 3 percent compared to subcritical units. In other words, less fuel needs to be burned to generate the same electrical output.

The boiler will be furnished with six to seven pulverizers, including one spare, and will have tangentially fired or wall-fired (front and rear) low nitrogen oxides (NO_x) burners and overfire air ports. The unit will be designed for baseload operation and will have a maximum gross heat input of approximately 7,475 MMBtu/hr¹ and a gross nominal plant output of approximately 818.5 megawatts (MW).

¹The maximum gross heat input is based on design coal characteristics associated with a blend of 78 percent PRB and 22 percent petcoke, summer design ambient conditions, at 100-percent load plus a 5-percent margin on boiler heat input.

Fuel flexibility needed to maintain competitively priced sources of coal is an important TEC design criterion. As previously discussed in Section 2.2, the main boiler will be designed to fire 100-percent bituminous coal, blends of bituminous and subbituminous coals, and blends of bituminous or subbituminous coal with petcoke. The maximum amount of petcoke blended with coal will be up to approximately 30 percent by weight. Bituminous coal for the proposed facility will typically be from either Latin America or Central Appalachia. Subbituminous coal will typically be from the PRB area of northeast Wyoming.

Flue gas from the proposed boiler will pass through the AQCS equipment and discharge to atmosphere through one 550-foot (ft) stack. Proposed BACT control technologies include:

- Low-NO_x burners and overfire air to minimize the formation of NO_x.
- SCR for NO_x control and mercury removal enhancement.
- Fabric filter baghouse for control of particulate matter (PM) and mercury.
- Wet limestone, forced oxidation FGD for SO₂, mercury, and hazardous air pollutant (HAP) control.
- WESP for sulfuric acid (H₂SO₄) mist, condensable fine particulate, and mercury control.

As indicated, in addition to its primary function, each air emission control device listed will have a cobenefit of removing mercury and/or contributing to the removal of mercury. In addition, the TEC Project will be designed with specific mercury control technology(ies) (i.e., fuel and/or FGD additives) to further minimize mercury emissions.

Figure 2-5 provides a schematic showing the main boiler process and AQCS.

2.3.2 AUXILIARY BOILER

The TEC Project will include an auxiliary boiler to provide steam during startup and low-load operation for turbine gland seals, deaerator pegging, condensate drains tank sparging, combustion air preheating, condenser steam jet air ejectors, and the wastewater

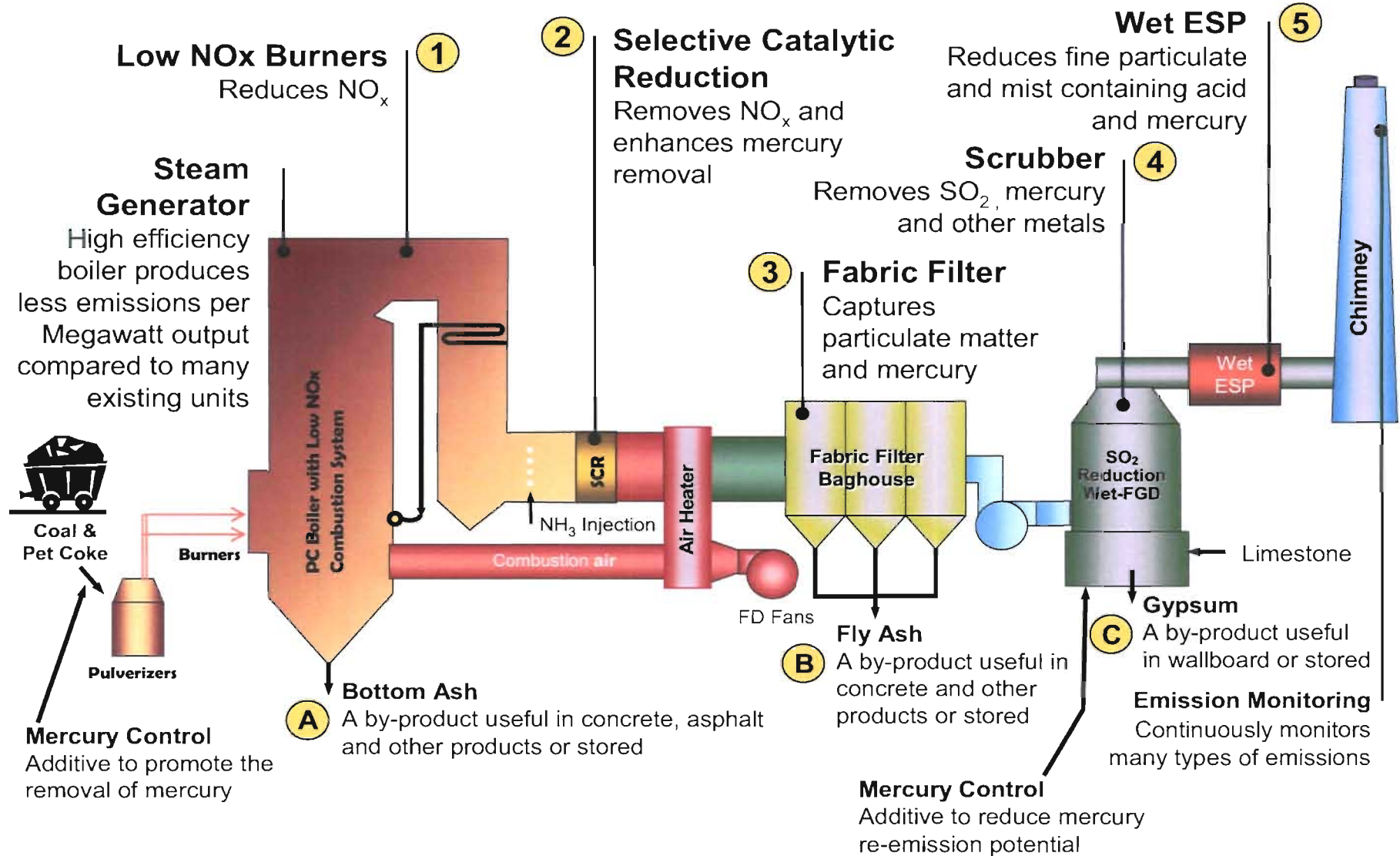


FIGURE 2-5.

TEC EMISSIONS CONTROL SYSTEMS

Source: S&L, 2007.

system crystallizer. Auxiliary steam generated by the auxiliary boiler will also be used to support boiler hydrostatic testing and chemical cleaning during startup. The auxiliary boiler will be rated for 220,000 lb/hr steam at 233 psig.

The main boiler is expected to have an average annual capacity factor of approximately 90 percent with 12 or fewer starts each year; therefore, operation of the auxiliary boiler should be infrequent. Based on the estimated annual number and duration of main boiler starts, the need for maintaining turbine steam seals, and the potential need for auxiliary steam during the annual maintenance outage, the auxiliary boiler is expected to operate up to 876 hr/yr.

The auxiliary boiler will be equipped with low-NO_x burners and flue gas recirculation (FGR) to control NO_x emissions and will be fired with ULSD fuel oil (maximum sulfur content of 0.0015 percent).

2.3.3 COOLING TOWER

The TEC Project cooling tower will be a multicelled, counter-flow, back-to-back style tower. The structure will have 20 cells made from fiberglass material with stainless steel hardware, high efficiency fill, and drift eliminators. Each cell will contain a fan with a 250-horsepower (hp) (approximately) drive motor. The structure will be erected over a concrete basin.

Cooling tower evaporation loss at maximum load is estimated to be 9 million gallons per day (MGD). A blowdown of approximately 1 MGD will maintain the maximum level of total dissolved solids (TDS) in the circulating water in the closed loop system at about ten cycles of concentration. Cooling tower blowdown will be routed to the plant's process wastewater ponds.

The primary source of makeup water to replace cooling tower evaporation, drift, and blowdown will be industrial wastewater from the Buckeye pulp mill. In the event of a mill maintenance outage or an unplanned interruption of Buckeye wastewater flow, the backup water source for cooling tower makeup will be from the onsite wells.

PM/particulate matter less than or equal to 10 micrometers (PM₁₀) emissions from the TEC cooling tower will be controlled using high efficiency drift eliminators. The cooling tower will achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow.

2.3.4 EMERGENCY EQUIPMENT

An emergency generator will be provided to supply power to the essential service motor control centers during an interruption of electrical power supply to the site. Typical essential service loads include turbine and boiler feed pump turning gear motors, critical oil pumps, air preheater recirculating pumps, hydrogen side seal oil pumps, flame detector cooling air fans, air heaters, fuel supply systems, plant communication systems, and essential emergency lighting. The size of the emergency generator will be approximately 1,640 kilowatts (kW). The emergency generator will fire ULSD fuel oil and will include advanced combustion modifications, including retard timing, to minimize potential NO_x emissions. It is estimated that the emergency generator will be operated for a maximum of 96 hr/yr for routine testing purposes (i.e., excluding emergencies).

Fire protection water will be supplied from the circulating water makeup system treated water storage tank. The storage tank will be designed to retain a minimum 2-hour volume of water for fire protection. The fire protection system will consist of two 3,000-gallon-per-minute (gpm) capacity main firewater pumps (one electric driven pump and one emergency diesel driven pump), a 40-gpm pressure maintenance pump and a network of fire protection piping, hydrants, hose stations, and spray nozzles. Based on preliminary design criteria, it is estimated that the emergency firewater pump diesel engine will be rated at 432 hp and will operate a maximum of 96 hr/yr for routine testing purposes (i.e., excluding emergencies). The emergency firewater pump diesel engine will be fired with ULSD fuel oil.

The emergency generator and firewater pump diesels will comply with the applicable emission limits of New Source Performance Standard (NSPS) Subpart IIII for new non-road compression ignition (CI) engines.

2.3.5 SOLID FUEL HANDLING SYSTEMS

Design of the solid fuel handling and storage system focuses on ease of delivery and unloading procedures, location of long-term storage, fuel blending capability, and minimizing noise and dust associated with coal and petcoke processing. Descriptions of solid fuel unloading, transfer and storage, and processing are provided in the following subsections.

2.3.5.1 Solid Fuel Unloading

A new single rail spur will be constructed between the existing Georgia & Florida Railway track and the TEC site boundary. The track will bifurcate onsite providing access to and egress from a 14,000-ft double track rail loop. The rail loop will be designed to accommodate three unit trains. One unit train will be unloaded at a time. Bottom dump coal cars will be emptied into below-grade hoppers at a rate of approximately 3,000 tons per hour (ton/hr). Spray water, with surfactant, as needed, will be applied to the solid fuel during unloading to suppress dust emissions. Depending on the number and position of onsite unit trains, an unloaded train will either immediately exit the Site or circle the loop track so waiting trains can be repositioned to create access to the single track leaving the Site. From the hoppers, the solid fuel will be conveyed to a transfer house and then to either the active storage area or stock-out piles.

2.3.5.2 Solid Fuel Transfer and Storage

TEC will have active and inactive storage piles for both coal and petcoke (or an alternative second coal depending on pet coke availability). The inactive storage piles will be used to maintain an inventory of fuel onsite for use in the event of delivery interruptions. The inactive storage piles will be designed to store enough fuel to operate TEC for approximately 90 days at 100-percent capacity.

Solid fuel unloaded into the bottom dump hoppers will be conveyed to a transfer house and then to either the active storage area or a stock-out pile. Residual chemical dust suppression will be applied to solid fuel conveyed to the active storage area or stock-out piles. In the event the active storage is at full capacity or an active storage conveyor is out

of service, then solid fuel unloaded from the train will be conveyed from the transfer house to one of two conical stock-out piles. Solid fuel will be discharged to the stock-out piles through a telescopic chute to minimize fugitive dust emissions. Each stock-out pile will have sufficient capacity to accommodate the contents of a unit train. Solid fuel in a stock-out pile will be bulldozed to the adjacent inactive storage area or reclaimed at a later time to either restock the active storage area or fill the boiler fuel storage silos.

The active solid fuel storage area will be located in a covered shed beneath an elevated tripper conveyor. Two separate fuel piles will be maintained in the shed typically consisting of one pile for coal and one pile for petcoke. The active storage area will contain up to 45,000 tons of solid fuel, which is equivalent to approximately 5 days of operation at maximum boiler load. Wet sprays will be used to control fugitive dust in the active storage shed. Solid fuel unloading, stacker, and reclaim conveyors will be enclosed to minimize fugitive dust emissions. Reclaimed solid fuel passing through enclosed transfer points will be treated with fogging dust suppression sprays or vented to a fabric filter.

Fuel in the stock-out piles will be moved by bulldozer to inactive storage areas. Separate inactive storage piles will be provided for coal and petcoke (or an alternative second coal type) designed to store sufficient fuel for approximately 90 days of operation at 100-percent capacity. The inactive coal storage pile will cover an area approximately 1,000 by 600 ft and be approximately 45 ft high. The inactive coal storage pile will contain approximately 651,000 tons of coal. Coal will be delivered to the inactive storage pile by bulldozing from the coal stock-out pile. The inactive storage pile will be compacted and treated with a water or surfactant spray to minimize potential dust emissions.

The inactive petcoke storage pile will be approximately 500 by 400 ft and 40 ft high. The inactive petcoke storage pile will contain approximately 208,000 tons of petcoke. The inactive petcoke storage pile will be compacted and treated with a water or surfactant spray to minimize potential dust emissions.

2.3.5.3 Solid Fuel Processing

Two portal scraper reclaimers will be installed over the active fuel storage piles. Working together, the two reclaimers will transfer coal and petcoke (or a second coal) in a controlled ratio onto the solid fuel active reclaim conveyor. The enclosed solid fuel active reclaim conveyor will deliver the fuel blend to the transfer house and on to one of two 100-percent capacity enclosed main conveyors. The main conveyor will deliver the fuel to one of two surge bins located in the crusher house. From the surge bin, the fuel will be fed into one of two 900-ton/hr crushers. Fuel will be crushed from its delivered size of approximately 3 by 0 inch to 1.25 by 0 inch. Crushed fuel will be conveyed to the in-service storage silos located above the pulverizers adjacent to the main boiler. Each silo has a total storage capacity sufficient for 16 hours of operation at 100-percent boiler capacity.

PM/PM₁₀ emissions from the solid fuel systems will be controlled using fogging dust suppression sprays (with surfactant, as needed), enclosures, fabric filters (where feasible), and surface crusting agents.

Figure 2-6 provides a process flow diagram of the solid fuel systems.

2.3.6 LIQUID FUEL STORAGE AND HANDLING

ULSD fuel oil will be used in the auxiliary boiler and for main boiler startups. ULSD fuel oil will be delivered to the Site by tanker truck and stored in a 300,000-gallon steel storage tank within a lined spill containment berm. Smaller ULSD fuel oil day storage tanks for the emergency fire pumps and emergency generator will be located within concrete containment areas.

2.3.7 LIMESTONE STORAGE AND HANDLING

Limestone will be used as a reagent in the FGD system and will be delivered to the site by 22-ton capacity haul trucks. The TEC Project will have active and inactive limestone storage piles. The active storage conical pile will be covered and will hold approximately a 10-day supply of limestone. The inactive limestone pile will measure 200 by 200 by 30 ft high and will contain approximately a 90-day supply of limestone.

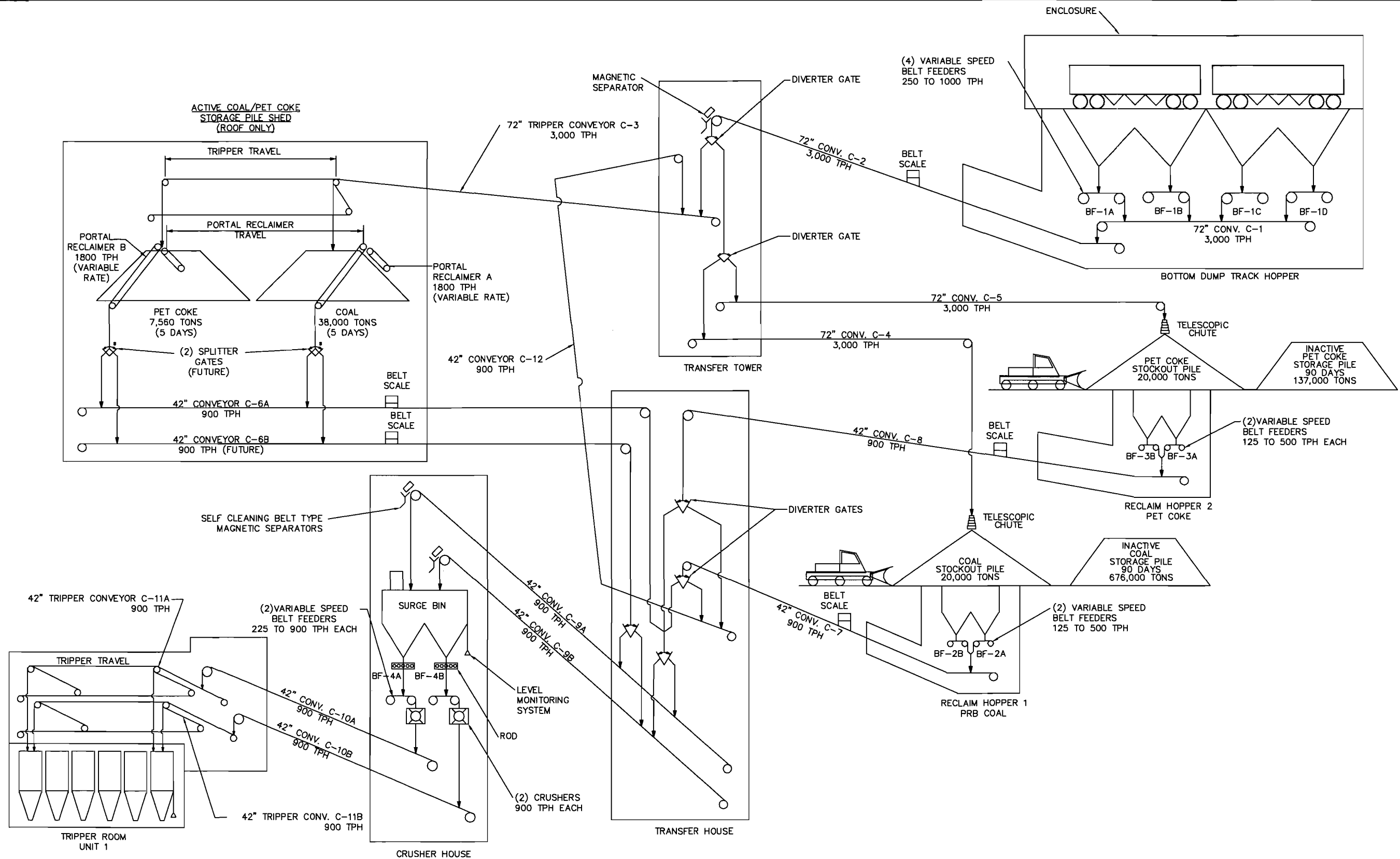


FIGURE 2-6.

COAL HANDLING SYSTEM FLOW DIAGRAM

Source: Sargent & Lundy, 2006.

Each haul truck will unload limestone into a hopper where feeders will transfer the limestone onto the unloading conveyor. The unloading conveyor will transport the limestone to the active stack-out pile. Limestone will be bulldozed from the stack-out pile to the inactive storage pile for long-term storage. The inactive storage pile will be compacted and treated with water and surfactant sprays to minimize potential dust emissions.

Limestone will be reclaimed from the active storage pile through a hopper. Reclaim hopper feeders will transfer limestone to the enclosed limestone reclaim conveyor. The reclaim conveyor will deliver limestone to one of two day bins. Limestone will be transferred from the day bins to the limestone ball mills via a weigh feeder.

Figure 2-7 provides a process flow diagram of limestone handling system.

2.3.8 ANHYDROUS AMMONIA STORAGE AND HANDLING

Anhydrous ammonia will be used as a reagent in the main boiler SCR NO_x emission control system. Anhydrous ammonia will be delivered by rail or truck and stored in one or two outdoor 30,000-gallon tanks designed and fabricated in accordance with U.S. Department of Labor Chapter 29, Part 1910.111, Code of Federal Regulations (CFR), American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, American National Standards Institute (ANSI) K 61.1, and Chapter 62-762, Florida Administrative Code (F.A.C.), requirements. The tanks will be located within a concrete containment basin located approximately 2,000 ft southwest of the plant administration and service building and approximately 3,500 ft from the nearest site boundary fence.

The ammonia storage tanks will be shielded from overhead sunlight. Also, the tanks will be protected from airborne projectiles by use of suitable barriers. A fire hydrant will be located within 100 ft of the storage area, and emergency showers and eyewash stations will be located both inside and outside of the tank containment basin.

Truck deliveries will be transferred to the storage tanks by pumps located on the trailer. Ammonia delivered by rail car will be unloaded using one of two 100-percent unloading

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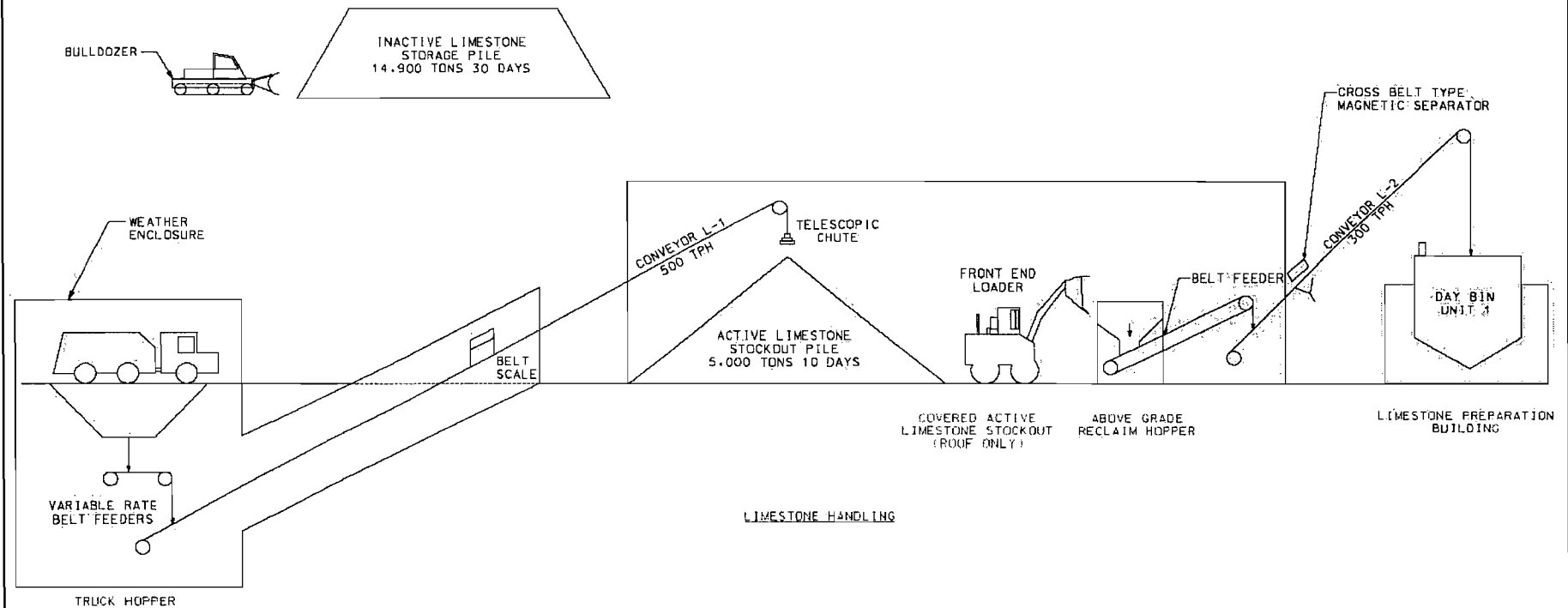


FIGURE 2-7.

TYPICAL LIMESTONE HANDLING FLOW DIAGRAM

Source: S&L, 2006.



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compressors installed at a rail car unloading station. The anhydrous ammonia flow rate will be approximately 820 lb/hr, which translates to approximately four trucks (7,000 gallons per truck) or one rail car (33,000 gallons per rail car) per week.

The process for using anhydrous ammonia in SCR systems consists of conveying stored liquid ammonia by ammonia supply pumps. Liquid ammonia will be transferred to a vaporizer that heats the ammonia and vaporizes the liquid ammonia to a gas. The ammonia vapor leaving the vaporizer will be mixed with dilution air and transported to the injection grid in the flue gas, upstream of the SCR reactor. The concentration of anhydrous ammonia required for NO_x reduction is regulated by the ammonia control system. As the NO_x emission levels increase or decrease, the ammonia supply pump output level changes accordingly.

2.3.9 COMBUSTION BYPRODUCT STORAGE AND HANDLING

Fly ash, bottom ash, and gypsum byproducts produced in the FGD system will be marketed and sold for offsite commercial uses, to the extent possible. The TEC site development plan includes space for long-term (i.e., 30-year life of project) storage areas for these byproducts in the event adequate offsite commercial uses are not available. During initial construction, lined cells in the byproduct storage areas will be developed for up to 8 years of storage of each byproduct. Additional cells will be developed only as needed to minimize onsite land area disturbance. Based on commercial considerations and market conditions, there may be times when it will be advantageous to mix the byproducts, fly ash, bottom ash, and gypsum in the onsite storage areas. In these instances, various blends of byproduct will be stored in any of the three byproduct storage areas.

Bottom ash, fly ash, and FGD gypsum solid byproducts hauled to the lined onsite storage cells will remain uncapped while the cells are actively managed. During this time contact rainfall runoff and leachate will be collected and pumped into leachate ponds adjacent to the solid byproduct storage cells. Leachate water will be pumped through a spray irrigation pipe system onto the exposed solid byproduct surfaces to suppress fugitive dust.

Descriptions of the fly ash, bottom ash, and gypsum handling systems are provided in the following subsections.

2.3.9.1 Fly Ash Handling

Fly ash will be collected from the fabric filter hoppers and transported pneumatically to one of two short-term fly ash storage silos. Fly ash marketed offsite as a coal combustion byproduct will be unloaded dry into enclosed tanker-style haul trucks. Fly ash that cannot be marketed or removed from the Site before the short-term silo capacity is exceeded will be processed through a pin mixer and loaded into open top haul trucks. Well water added to fly ash in the pin mixer will eliminate the potential for fugitive dust emissions while the truck hauls onsite fly ash to a storage cell located east of the bottom ash storage area.

PM/PM₁₀ emissions resulting from the pneumatic transfer of fly ash will be controlled by fabric filters.

2.3.9.2 Bottom Ash Handling

Bottom ash will be collected in a bottom ash hopper located below the boiler and removed using a submerged drag chain conveyor. Most water contained in bottom ash removed from the hopper is collected off the conveyor and recycled to the hopper. The bottom ash and the small amount of remaining water will be conveyed to a three-sided concrete bunker located near the boiler. A front-end loader will be used to transfer the moist bottom ash to haul trucks.

Moist bottom ash along with pyrites collected in the bottom ash day bin or haul truck will be hauled offsite for commercial reuse or trucked to the bottom ash storage cell located south of the stack.

2.3.9.3 Gypsum Handling

FGD slurry containing spent reagent will be extracted from the scrubber tower recycle tank and processed through the gypsum production facility. The last step in the production process washes and dewateres the gypsum byproduct using a vacuum filter. Dewatered gypsum will be conveyed to and stacked inside a covered storage shed. Marketable

gypsum will be loaded into covered trucks using a front-end loader and removed from the site. Inferior quality gypsum or amounts that exceed the storage pile capacity will be loaded into trucks and hauled to the FGD byproduct storage cell located east of the stack.

Process flow diagrams of the fly ash, bottom ash, and gypsum combustion byproduct handling systems are provided in Figures 2-8 through 2-10, respectively.

2.4 EMISSIONS AND STACK PARAMETERS

Emission sources at TEC include:

- Supercritical pulverized coal-fired main boiler.
- Auxiliary boiler.
- Mechanical draft cooling tower.
- Emergency generator diesel engine.
- Emergency firewater pump diesel engine.
- Material (solid fuels, limestone, and combustion byproduct) handling systems.
- ULSD fuel oil storage tank.

The primary source of emissions from the TEC Project will result from the combustion of solid fuels in the main boiler. Principal air contaminants that will be emitted from the main boiler stack include NO_x, SO₂, carbon monoxide (CO), volatile organic compounds (VOC), PM/PM₁₀, hydrogen fluoride (HF), hydrochloride (HCl), and H₂SO₄. The main boiler will also emit trace amounts of metallic and organic compounds. A summary of maximum criteria pollutant (NO_x, SO₂, CO, VOC, PM/PM₁₀, and lead) emission rates for the main boiler is provided in Table 2-7. This table provides maximum emission rates estimated for each of the five fuel blends planned for the TEC Project for various averaging periods of interest in units of pounds per million British thermal units (lb/10⁶ Btu), pounds per megawatt-hour (lb/MWh), pounds per hour (lb/hr), and tons per year (tpy).

Estimates of main boiler HF, HCl, H₂SO₄, and mercury emissions are provided in Table 2-8. Although carbon dioxide (CO₂) is not a regulated pollutant, estimates of CO₂

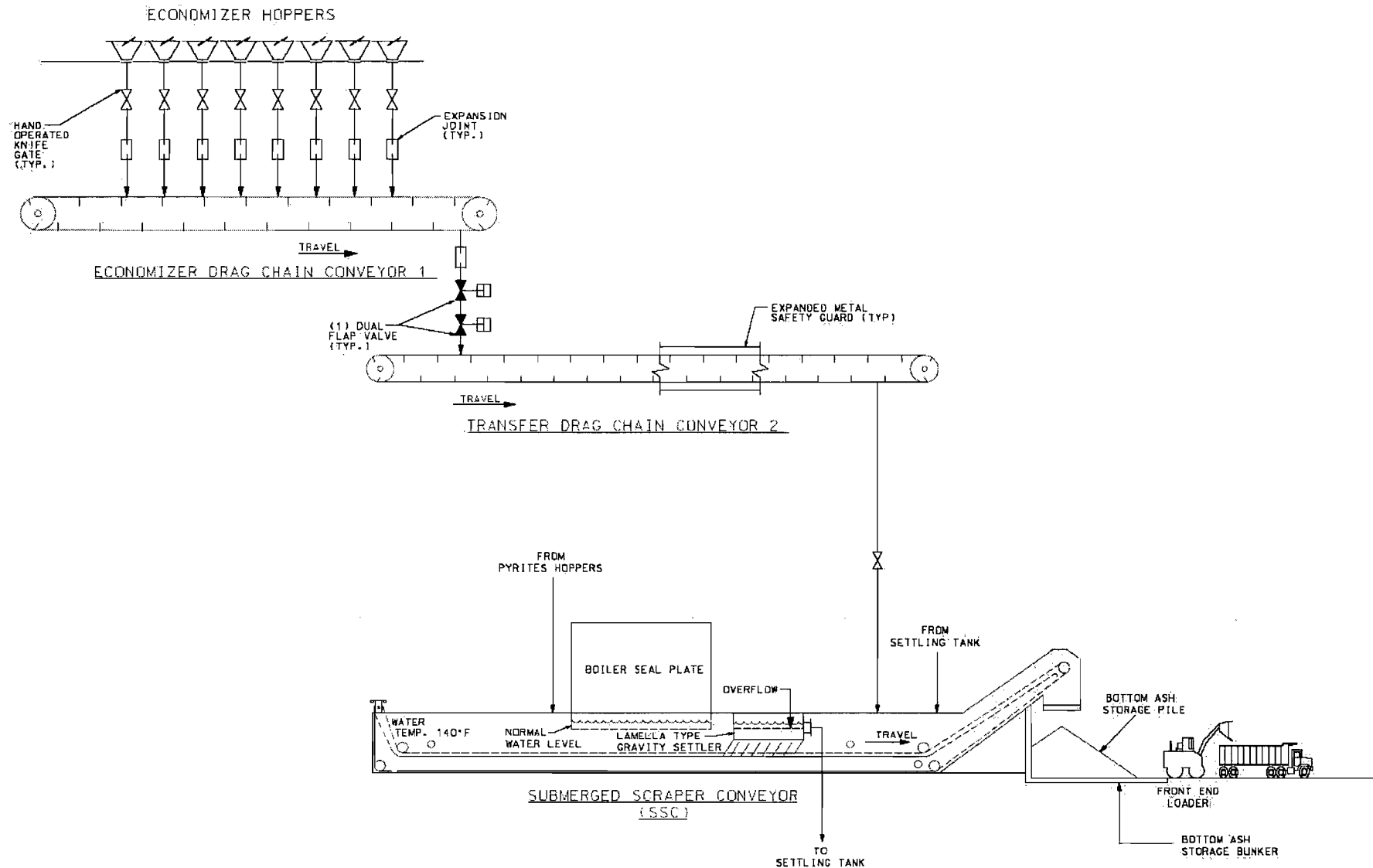


FIGURE 2-8.

TYPICAL BOTTOM ASH, ECONOMIZER ASH, AND PYRITE HANDLING FLOW DIAGRAM

Source: S&L, 2006.



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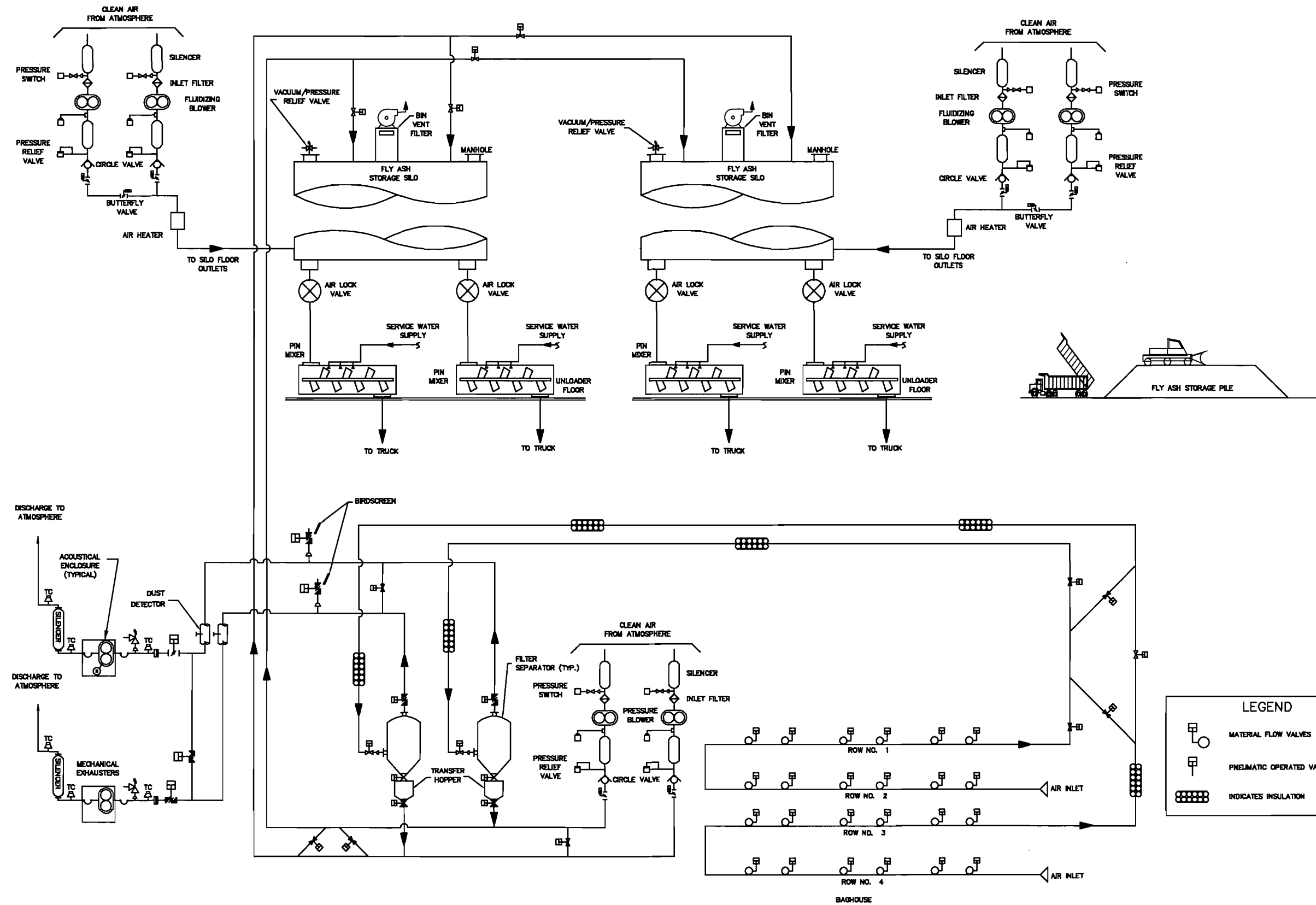


FIGURE 2-9.
TYPICAL FLY ASH HANDLING SYSTEM FLOW DIAGRAM

Source: Sargent & Lundy, 2006.

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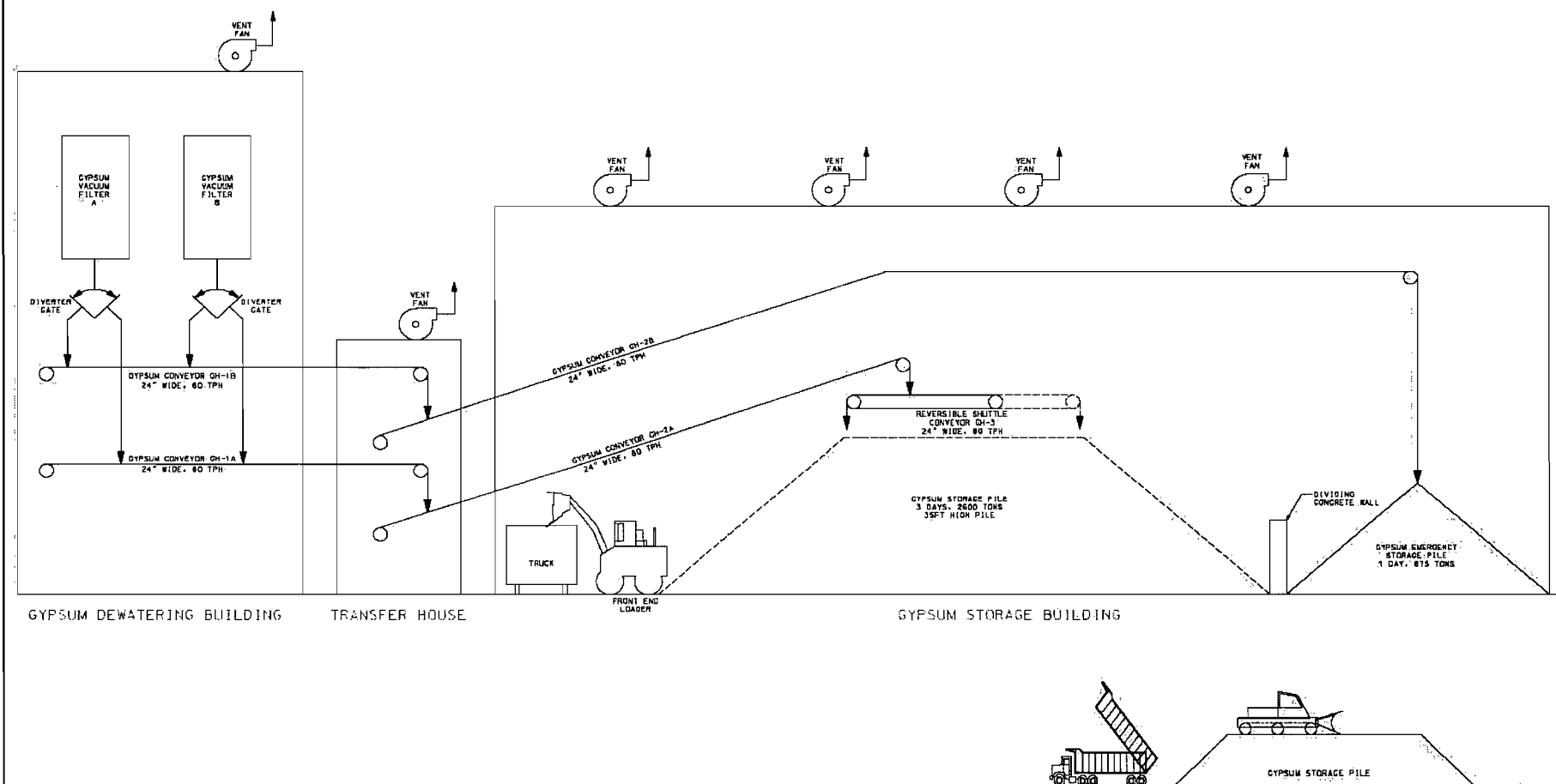


FIGURE 2-10.

TYPICAL GYPSUM HANDLING SYSTEM FLOW DIAGRAM

Source: S&L, 2006.



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Table 2-7. Main Solid Fuel-Fired Boiler—Criteria Pollutant Emission Rates

Pollutant	Averaging Period	Units	Fuel Type					Maximums
			Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Operating hours	Annual	hr/yr	8,760	8,760	8,760	8,760	8,760	8,760
Output (100-percent load)	Maximum hourly	MW, gross	818.5	818.5	818.5	818.5	818.5	818.5
Heat input (100-percent load)	Maximum hourly	10 ⁶ Btu/hr (HHV)	7,333	7,432	7,475	7,383	7,320	7,475
NO _x	30-Day and annual	lb/10 ⁶ Btu	0.050	0.050	0.050	0.050	0.050	0.050
		lb/MWh	0.448	0.454	0.457	0.451	0.447	0.457
		tpy	1,605.9	1,627.6	1,637.0	1,616.9	1,603.1	1,637
		lb/hr	366.7	371.6	373.8	369.2	366.0	373.8
		g/s	46.2	46.8	47.1	46.5	46.1	47.09
	24-Hour	lb/10 ⁶ Btu	0.050	0.050	0.050	0.050	0.050	0.050
		lb/MWh	0.448	0.454	0.457	0.451	0.447	0.457
		lb/hr	366.7	371.6	373.8	369.2	366.0	373.8
		g/s	46.2	46.8	47.1	46.5	46.1	47.09
	SO ₂	lb/10 ⁶ Btu	0.040	0.040	0.040	0.040	0.040	0.040
		lb/MWh	0.358	0.363	0.365	0.361	0.358	0.365
		tpy	1,284.7	1,302.1	1,309.6	1,293.5	1,282.5	1,310
		lb/hr	293.3	297.3	299.0	295.3	292.8	299.0
		g/s	37.0	37.5	37.7	37.2	36.9	37.67
	24-Hour	lb/10 ⁶ Btu	0.055	0.055	0.055	0.055	0.055	0.055
		lb/MWh	0.493	0.499	0.502	0.496	0.492	0.502
		lb/hr	403.3	408.8	411.1	406.1	402.6	411.1
		g/s	50.8	51.5	51.8	51.2	50.7	51.80
	3-Hour	lb/10 ⁶ Btu	0.070	0.070	0.070	0.070	0.070	0.070
		lb/MWh	0.627	0.636	0.639	0.631	0.626	0.639
		lb/hr	513.3	520.2	523.3	516.8	512.4	523.3
		g/s	64.7	65.5	65.9	65.1	64.6	65.93
CO	1-Hour, 8-hour and annual	lb/10 ⁶ Btu	0.150	0.150	0.150	0.150	0.150	0.150
		lb/MWh	1.344	1.362	1.370	1.353	1.341	1.370
		tpy	4,817.8	4,882.8	4,911.1	4,850.6	4,809.2	4,911
		lb/hr	1,100.0	1,114.8	1,121.3	1,107.5	1,098.0	1,121.3
VOC	3-Hour and annual	g/s	138.6	140.5	141.3	139.5	138.3	141.28
		lb/10 ⁶ Btu	0.0029	0.0033	0.0036	0.0031	0.0029	0.0036
		lb/MWh	0.0260	0.0300	0.0329	0.0280	0.0259	0.0329
		tpy	93.1	107.4	117.9	100.2	93.0	117.9
		lb/hr	21.3	24.5	26.9	22.9	21.2	26.9
		g/s	2.7	3.1	3.4	2.9	2.7	3.39

Table 2-7. Main Solid Fuel-Fired Boiler—Criteria Pollutant Emission Rates (Continued, Page 2 of 2)

Pollutant	Averaging Period	Units	Fuel Type					Maximums
			Case 1 CA	Case 2 LA	Case 3 PRB/Peteoke	Case 4 LA/Peteoke	Case 5 CA/Peteoke	
Operating hours	Annual	hr/yr	8,760	8,760	8,760	8,760	8,760	8,760
Output (100-percent load)	Maximum hourly	MW, gross	818.5	818.5	818.5	818.5	818.5	818.5
Heat input (100-percent load)	Maximum hourly	10 ⁶ Btu/hr (HHV)	7,333	7,432	7,475	7,383	7,320	7,475
PM ₁₀ (filterable)	30-Day, 24-hour and annual	lb/10 ⁶ Btu	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130
		lb/MWh	0.1165	0.1180	0.1187	0.1173	0.1163	0.1187
		tpy	417.5	423.2	425.6	420.4	416.8	425.6
		lb/hr	95.3	96.6	97.2	96.0	95.2	97.2
PM ₁₀ (condensable)	30-Day, 24-hour and annual	g/s	12.0	12.2	12.2	12.1	12.0	12.24
		lb/10 ⁶ Btu	0.0120	0.0095	0.0113	0.0110	0.0119	0.0120
		lb/MWh	0.1075	0.0863	0.1032	0.0992	0.1064	0.1075
		tpy	385.4	309.2	370.0	355.7	381.5	385.4
PM ₁₀ (total)	30-Day, 24-hour and annual	lb/hr	88.0	70.6	84.5	81.2	87.1	88.0
		g/s	11.1	8.9	10.6	10.2	11.0	11.09
		lb/10 ⁶ Btu	0.0250	0.0225	0.0243	0.0240	0.0249	0.0250
		lb/MWh	0.2240	0.2043	0.2219	0.2165	0.2227	0.2240
Lead	1-Hour and annual	tpy	803.0	732.4	795.6	776.1	798.3	803.0
		lb/hr	183.3	167.2	181.6	177.2	182.3	183.3
		g/s	23.1	21.1	22.9	22.3	23.0	23.10
		lb/10 ⁶ Btu	0.0000023	N/A	0.0000039	N/A	0.0000023	0.0000039
Lead	1-Hour and annual	lb/MWh	0.000021		0.000035		0.000021	0.000035
		tpy	0.074		0.127		0.074	0.13
		lb/hr	0.0170		0.0290		0.0170	0.029
		g/s	0.0021		0.0037		0.0021	0.0037

Note: CA = Central Appalachian.
 PRB = Powder River Basin.
 LA = Latin America.

Sources: S&L, 2007.
 ECT, 2007.

Table 2-8. Main Solid Fuel-Fired Boiler—HF, HCl, H₂SO₄, Mercury, and CO₂ Emission Rates

Pollutant	Averaging Period	Units	Fuel Type					Maximums
			Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Output	Maximum	MW, gross	818.5	818.5	818.5	818.5	818.5	818.5
Heat input (100-percent load)	Maximum hourly	10 ⁶ Btu/hr (HHV)	7,333	7,432	7,475	7,383	7,320	7,475
HF	3-Hour	lb/10 ⁶ Btu	0.00045	0.00047	0.00046	0.00045	0.00044	0.00047
		lb/MWh	0.0040	0.0043	0.0042	0.0041	0.0039	0.0043
		tpy	14.453	15.300	15.061	14.552	14.107	15.300
		lb/hr	3.30	3.49	3.44	3.32	3.22	3.5
		g/s	0.42	0.44	0.43	0.4	0.4	0.4
HCl	3-Hour	lb/10 ⁶ Btu	0.0046	0.0019	0.0036	0.0035	0.0045	0.0046
		lb/MWh	0.041	0.017	0.033	0.032	0.040	0.041
		tpy	147.745	61.849	117.866	113.181	144.277	147.745
		lb/hr	33.7	14.1	26.9	25.8	32.9	33.7
		g/s	4.3	1.8	3.4	3.3	4.2	4.3
H ₂ SO ₄	3-Hour	lb/10 ⁶ Btu	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040
		lb/MWh	0.036	0.036	0.037	0.036	0.036	0.037
		tpy	128.474	130.209	130.962	129.350	128.246	130.962
		lb/hr	29.3	29.7	29.9	29.5	29.3	29.90
		g/s	3.7	3.7	3.8	3.7	3.7	3.8
Hg	Annual	lb/10 ¹² Btu	0.60	0.89	0.89	0.90	0.48	0.90
		16×10 ⁻⁶ /MWh	5.4	8.1	8.1	8.1	4.3	8.1
		lb/yr	38.7	58.0	58.2	58.0	30.9	58.2
CO ₂	Annual	ton/10 ⁶ Btu	0.10	0.11	0.10	0.11	0.10	0.11
		ton/MWh	0.91	0.98	0.95	0.96	0.91	0.98
		ton/hr	742	800	774	787	742	800
		tpy	6,497,217	7,003,684	6,778,079	6,895,545	6,499,564	7,003,684

Note: CA = Central Appalachian.
 PRB = Powder River Basin.
 LA = Latin America.

Sources: S&L, 2007.
 ECT, 2007.

emissions are also included in Table 2-8 for informational purposes. Main boiler organic and metallic HAP emission rates are provided in Tables 2-9 and 2-10, respectively.

The auxiliary boiler, emergency generator diesel engine, and emergency firewater pump diesel engine will all be fired with ULSD fuel oil. Tables 2-11 through 2-13 provide summaries of maximum criteria pollutant emission rates for the auxiliary boiler, emergency generator diesel engine, and emergency firewater pump diesel engine, respectively.

The mechanical draft cooling tower will be equipped with high efficiency drift eliminators. PM/PM₁₀ will also be emitted by the material handling emission sources. A summary of the PM/PM₁₀ point and fugitive emissions for the cooling tower and material handling emission sources is provided in Table 2-14.

In addition to the emissions that will occur during operation of the TEC, there will be temporary emissions that will occur during the construction phase of the project. PM/PM₁₀ emissions will occur due to earthmoving activities associated with site preparation, wind erosion from disturbed areas, and vehicular traffic on unpaved roadways. The use of diesel engine heavy equipment will result in emissions of diesel fuel oil combustion products including NO_x, SO₂, CO, and VOC.

Reasonable precautions will be taken to minimize construction related emissions including watering of unpaved surfaces, as necessary, and use of ULSD by the heavy equipment. Idling of the heavy equipment, to the extent reasonable, will be minimized. Table 2-15 provides estimates of the construction related emissions.

An overall summary of maximum annual criteria and HAP pollutant emission rates for the TEC Project is provided in Tables 2-16 and 2-17, respectively. Appendix A provides detailed emission rate calculations.

Stack parameters for the main boiler for 100-, 75-, and 50-percent loads are provided in Table 2-18. Table 2-19 provides stack parameters for the auxiliary boiler, cooling tower, emergency generator diesel engine, and emergency firewater pump diesel engine.

Table 2-9. Main Solid Fuel-Fired Boiler—Organic Hazardous Air Pollutant Emission Rates

Pollutant	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5CA/Petcoke	
Maximum fuel consumption	ton/hr	299	336	377	316	293	377
1,1,1-Trichloroethane	lb/ton fuel	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05
	lb/hr	5.98E-03	6.72E-03	7.54E-03	6.32E-03	5.86E-03	7.54E-03
	tpy	0.0262	0.0294	0.0330	0.0277	0.0257	0.0330
2,4-Dinitrotoluene	lb/ton fuel	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
	lb/hr	8.37E-05	9.41E-05	1.06E-04	8.85E-05	8.20E-05	1.06E-04
	tpy	0.0004	0.0004	0.0005	0.0004	0.0004	0.0005
2-Chloroacetophenone	lb/ton fuel	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06
	lb/hr	2.09E-03	2.35E-03	2.64E-03	2.21E-03	2.05E-03	2.64E-03
	tpy	0.0092	0.0103	0.0116	0.0097	0.0090	0.0116
Acetaldehyde	lb/ton fuel	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06
	lb/hr	2.09E-03	2.35E-03	2.64E-03	2.21E-03	2.05E-03	2.64E-03
	tpy	0.0092	0.0103	0.0116	0.0097	0.0090	0.0116
Acetophenone	lb/ton fuel	1.50E-05	1.50E-05	1.50E-05	1.50E-05	1.50E-05	1.50E-05
	lb/hr	4.49E-03	5.04E-03	5.66E-03	4.74E-03	4.40E-03	5.66E-03
	tpy	0.0196	0.0221	0.0248	0.0208	0.0193	0.0248
Acrolein	lb/ton fuel	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04
	lb/hr	8.67E-02	9.74E-02	1.09E-01	9.16E-02	8.50E-02	1.09E-01
	tpy	0.3798	0.4268	0.4789	0.4014	0.3722	0.4789
Benzene	lb/ton fuel	1.30E-03	1.30E-03	1.30E-03	1.30E-03	1.30E-03	1.30E-03
	lb/hr	3.89E-01	4.37E-01	4.90E-01	4.11E-01	3.81E-01	4.90E-01
	tpy	1.7025	1.9132	2.1466	1.7993	1.6683	2.1466
Benzyl chloride	lb/ton fuel	7.00E-04	7.00E-04	7.00E-04	7.00E-04	7.00E-04	7.00E-04
	lb/hr	2.09E-01	2.35E-01	2.64E-01	2.21E-01	2.05E-01	2.64E-01
	tpy	0.9167	1.0302	1.1559	0.9689	0.8983	1.1559
Biphenyl	lb/ton fuel	1.70E-06	1.70E-06	1.70E-06	1.70E-06	1.70E-06	1.70E-06
	lb/hr	5.08E-04	5.71E-04	6.41E-04	5.37E-04	4.98E-04	6.41E-04
	tpy	0.0022	0.0025	0.0028	0.0024	0.0022	0.0028
Bis(2-ethylhexyl)phthalate (DEHP)	lb/ton fuel	7.30E-05	7.30E-05	7.30E-05	7.30E-05	7.30E-05	7.30E-05
	lb/hr	2.18E-02	2.45E-02	2.75E-02	2.31E-02	2.14E-02	2.75E-02
	tpy	0.0956	0.1074	0.1205	0.1010	0.0937	0.1205
Bromoform	lb/ton fuel	3.90E-05	3.90E-05	3.90E-05	3.90E-05	3.90E-05	3.90E-05
	lb/hr	1.17E-02	1.31E-02	1.47E-02	1.23E-02	1.14E-02	1.47E-02
	tpy	0.0511	0.0574	0.0644	0.0540	0.0501	0.0644
Carbon disulfide	lb/ton fuel	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04
	lb/hr	3.89E-02	4.37E-02	4.90E-02	4.11E-02	3.81E-02	4.90E-02
	tpy	0.1703	0.1913	0.2147	0.1799	0.1668	0.2147
Chlorobenzene	lb/ton fuel	2.20E-05	2.20E-05	2.20E-05	2.20E-05	2.20E-05	2.20E-05
	lb/hr	6.58E-03	7.39E-03	8.29E-03	6.95E-03	6.45E-03	8.29E-03
	tpy	0.0288	0.0324	0.0363	0.0304	0.0282	0.0363
Chloroform	lb/ton fuel	5.90E-05	5.90E-05	5.90E-05	5.90E-05	5.90E-05	5.90E-05
	lb/hr	1.76E-02	1.98E-02	2.22E-02	1.86E-02	1.73E-02	2.22E-02
	tpy	0.0773	0.0868	0.0974	0.0817	0.0757	0.0974

Table 2-9. Main Solid Fuel-Fired Boiler—Organic Hazardous Air Pollutant Emission Rates (Continued, Page 2 of 3)

Pollutant	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case SCA/Petcoke	
Maximum fuel consumption	ton/hr	299	336	377	316	293	377
Cumene	lb/ton fuel	5.30E-06	5.30E-06	5.30E-06	5.30E-06	5.30E-06	5.30E-06
	lb/hr	1.58E-03	1.78E-03	2.00E-03	1.67E-03	1.55E-03	2.00E-03
	tpy	0.0069	0.0078	0.0088	0.0073	0.0068	0.0088
Cyanide	lb/ton fuel	2.50E-03	2.50E-03	2.50E-03	2.50E-03	2.50E-03	2.50E-03
	lb/hr	7.48E-01	8.40E-01	9.43E-01	7.90E-01	7.33E-01	9.43E-01
	tpy	3.2741	3.6792	4.1282	3.4602	3.2084	4.1282
Dibenzofurans (total PCDD/PCDF)	lb/ton fuel	1.76E-09	1.76E-09	1.76E-09	1.76E-09	1.76E-09	1.76E-09
	lb/hr	5.26E-07	5.91E-07	6.64E-07	5.56E-07	5.16E-07	6.64E-07
	tpy	0.000002	0.000003	0.000003	0.000002	0.000002	0.000003
Dimethyl sulfate	lb/ton fuel	4.80E-05	4.80E-05	4.80E-05	4.80E-05	4.80E-05	4.80E-05
	lb/hr	1.44E-02	1.61E-02	1.81E-02	1.52E-02	1.41E-02	1.81E-02
	tpy	0.0629	0.0706	0.0793	0.0664	0.0616	0.0793
Ethyl benzene	lb/ton fuel	9.40E-05	9.40E-05	9.40E-05	9.40E-05	9.40E-05	9.40E-05
	lb/hr	2.81E-02	3.16E-02	3.54E-02	2.97E-02	2.75E-02	3.54E-02
	tpy	0.1231	0.1383	0.1552	0.1301	0.1206	0.1552
Ethyl chloride	lb/ton fuel	4.20E-05	4.20E-05	4.20E-05	4.20E-05	4.20E-05	4.20E-05
	lb/hr	1.26E-02	1.41E-02	1.58E-02	1.33E-02	1.23E-02	1.58E-02
	tpy	0.0550	0.0618	0.0694	0.0581	0.0539	0.0694
Ethylene dibromide	lb/ton fuel	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06
	lb/hr	3.59E-04	4.03E-04	4.52E-04	3.79E-04	3.52E-04	4.52E-04
	tpy	0.0016	0.0018	0.0020	0.0017	0.0015	0.0020
Ethylene dichloride	lb/ton fuel	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05
	lb/hr	1.20E-02	1.34E-02	1.51E-02	1.26E-02	1.17E-02	1.51E-02
	tpy	0.0524	0.0589	0.0661	0.0554	0.0513	0.0661
Formaldehyde	lb/ton fuel	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04
	lb/hr	7.18E-02	8.06E-02	9.05E-02	7.58E-02	7.03E-02	9.05E-02
	tpy	0.3143	0.3532	0.3963	0.3322	0.3080	0.3963
Hexane	lb/ton fuel	6.70E-05	6.70E-05	6.70E-05	6.70E-05	6.70E-05	6.70E-05
	lb/hr	2.00E-02	2.25E-02	2.53E-02	2.12E-02	1.96E-02	2.53E-02
	tpy	0.0877	0.0986	0.1106	0.0927	0.0860	0.1106
Isophorone	lb/ton fuel	5.80E-04	5.80E-04	5.80E-04	5.80E-04	5.80E-04	5.80E-04
	lb/hr	1.73E-01	1.95E-01	2.19E-01	1.83E-01	1.70E-01	2.19E-01
	tpy	0.7596	0.8536	0.9577	0.8028	0.7443	0.9577
Methyl bromide	lb/ton fuel	1.60E-04	1.60E-04	1.60E-04	1.60E-04	1.60E-04	1.60E-04
	lb/hr	4.78E-02	5.38E-02	6.03E-02	5.06E-02	4.69E-02	6.03E-02
	tpy	0.2095	0.2355	0.2642	0.2215	0.2053	0.2642
Methyl chloride	lb/ton fuel	5.30E-04	5.30E-04	5.30E-04	5.30E-04	5.30E-04	5.30E-04
	lb/hr	1.58E-01	1.78E-01	2.00E-01	1.67E-01	1.55E-01	2.00E-01
	tpy	0.6941	0.7800	0.8752	0.7336	0.6802	0.8752
Methyl ethyl ketone	lb/ton fuel	3.90E-04	3.90E-04	3.90E-04	3.90E-04	3.90E-04	3.90E-04
	lb/hr	1.17E-01	1.31E-01	1.47E-01	1.23E-01	1.14E-01	1.47E-01
	tpy	0.5108	0.5740	0.6440	0.5398	0.5005	0.6440

Table 2-9. Main Solid Fuel-Fired Boiler—Organic Hazardous Air Pollutant Emission Rates (Continued, Page 3 of 3)

Pollutant	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case SCA/Petcoke	
Maximum fuel consumption	ton/hr	299	336	377	316	293	377
Methyl hydrazine	lb/ton fuel	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04
	lb/hr	5.08E-02	5.71E-02	6.41E-02	5.37E-02	4.98E-02	6.41E-02
	tpy	0.2226	0.2502	0.2807	0.2353	0.2182	0.2807
Methyl methacrylate	lb/ton fuel	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05
	lb/hr	5.98E-03	6.72E-03	7.54E-03	6.32E-03	5.86E-03	7.54E-03
	tpy	0.0262	0.0294	0.0330	0.0277	0.0257	0.0330
Methyl tert-butyl ether	lb/ton fuel	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05
	lb/hr	1.05E-02	1.18E-02	1.32E-02	1.11E-02	1.03E-02	1.32E-02
	tpy	0.0458	0.0515	0.0578	0.0484	0.0449	0.0578
Methylene chloride	lb/ton fuel	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04
	lb/hr	8.67E-02	9.74E-02	1.09E-01	9.16E-02	8.50E-02	1.09E-01
	tpy	0.3798	0.4268	0.4789	0.4014	0.3722	0.4789
Naphthalene	lb/ton fuel	1.30E-05	1.30E-05	1.30E-05	1.30E-05	1.30E-05	1.30E-05
	lb/hr	3.89E-03	4.37E-03	4.90E-03	4.11E-03	3.81E-03	4.90E-03
	tpy	0.0170	0.0191	0.0215	0.0180	0.0167	0.0215
Phenol	lb/ton fuel	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05
	lb/hr	4.78E-03	5.38E-03	6.03E-03	5.06E-03	4.69E-03	6.03E-03
	tpy	0.0210	0.0235	0.0264	0.0221	0.0205	0.0264
Polycyclic aromatic hydrocarbons	lb/ton fuel	1.91E-05	1.91E-05	1.91E-05	1.91E-05	1.91E-05	1.91E-05
	lb/hr	5.70E-03	6.40E-03	7.18E-03	6.02E-03	5.58E-03	7.18E-03
	tpy	0.0250	0.0280	0.0315	0.0264	0.0245	0.0315
Propionaldehyde	lb/ton fuel	3.80E-04	3.80E-04	3.80E-04	3.80E-04	3.80E-04	3.80E-04
	lb/hr	1.14E-01	1.28E-01	1.43E-01	1.20E-01	1.11E-01	1.43E-01
	tpy	0.4977	0.5592	0.6275	0.5260	0.4877	0.6275
Styrene	lb/ton fuel	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05
	lb/hr	7.48E-03	8.40E-03	9.43E-03	7.90E-03	7.33E-03	9.43E-03
	tpy	0.0327	0.0368	0.0413	0.0346	0.0321	0.0413
Tetrachloroethylene	lb/ton fuel	4.30E-05	4.30E-05	4.30E-05	4.30E-05	4.30E-05	4.30E-05
	lb/hr	1.29E-02	1.44E-02	1.62E-02	1.36E-02	1.26E-02	1.62E-02
	tpy	0.0563	0.0633	0.0710	0.0595	0.0552	0.0710
Toluene	lb/ton fuel	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04
	lb/hr	7.18E-02	8.06E-02	9.05E-02	7.58E-02	7.03E-02	9.05E-02
	tpy	0.3143	0.3532	0.3963	0.3322	0.3080	0.3963
Vinyl Acetate	lb/ton fuel	7.60E-06	7.60E-06	7.60E-06	7.60E-06	7.60E-06	7.60E-06
	lb/hr	2.27E-03	2.55E-03	2.87E-03	2.40E-03	2.23E-03	2.87E-03
	tpy	0.0100	0.0112	0.0125	0.0105	0.0098	0.0125
Xylenes	lb/ton fuel	3.70E-05	3.70E-05	3.70E-05	3.70E-05	3.70E-05	3.70E-05
	lb/hr	1.11E-02	1.24E-02	1.39E-02	1.17E-02	1.08E-02	1.39E-02
	tpy	0.0485	0.0545	0.0611	0.0512	0.0475	0.0611

Note: Organic compound emission factors (lb per ton of fuel) taken from Tables 1.1-12, 1.1-13, and 1.1-14 of AP-42, EPA, September 1998.

Sources: S&L, 2007.
ECT, 2007.

Table 2-10. Main Solid Fuel-Fired Boiler—Metallic Hazardous Air Pollutant Emission Rates

Pollutant	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke*†	Case 4 LA/Petcoke	Case 5 CA/Petcoke†‡	
Maximum heat input	MMBtu/hr	7,333	7,432	7,475	7,383	7,320	7,475
Fuel ash fraction (A)	%/100	0.1404	0.0850	0.0441	0.0678	0.1222	0.1404
Controlled PM emission rate (PM)	lb/MMBtu	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130
Maximum fuel consumption	ton/hr	299	336	377	316	293	377
Emission factor	lb/MMBtu*†	$a \times (C / A \times PM)^b$; Table 1.1-16, AP-42, EPA, September 1998.					
Antimony (Sb)	C (ppmw)	1.15	N/A	0.53	N/A	1.15	1.15
	a	0.92		0.92		0.92	
	b	0.63		0.63		0.63	
	lb/MMBtu*†	0.225		0.285		0.225	
	lb/hr	0.0016		0.0021		0.0016	0.0021
	tpy	0.0072		0.0093		0.0072	0.0093
Arsenic (As)	C (ppmw)	21.93	N/A	5.28	N/A	21.93	21.93
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb/MMBtu*†	5.640		4.505		5.640	
	lb/hr	0.0414		0.0337		0.0414	0.0414
	tpy	0.1811		0.1475		0.1811	0.1811
Beryllium (Be)	C (ppmw)	2.80	N/A	0.75	N/A	2.80	2.80
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb/MMBtu*†	0.990		0.868		0.990	
	lb/hr	0.0073		0.0065		0.0073	0.0073
	tpy	0.0318		0.0284		0.0318	0.0318
Cadmium (Cd)	C (ppmw)	0.08	N/A	0.11	N/A	0.08	0.11
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb/MMBtu*†	0.050		0.168		0.050	
	lb/hr	0.0004		0.0013		0.0004	0.0013
	tpy	0.0016		0.0055		0.0016	0.0055
Chromium (Cr)	C (ppmw)	14.18	N/A	6.17	N/A	14.18	14.18
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb/MMBtu*†	3.902		5.138		3.902	
	lb/hr	0.0286		0.0384		0.0286	0.0384
	tpy	0.1253		0.1682		0.1253	0.1682
Cobalt (Co)	C (ppmw)	7.00	N/A	2.06	N/A	7.00	7.00
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb/MMBtu*†	2.149		2.034		2.149	
	lb/hr	0.0158		0.0152		0.0158	0.0158
	tpy	0.0690		0.0666		0.0690	0.0690
Lead (Pb)	C (ppmw)	7.64	N/A	4.42	N/A	7.64	7.64
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb/MMBtu*†	2.314		3.878		2.314	
	lb/hr	0.0170		0.0290		0.0170	0.0290
	tpy	0.0743		0.1270		0.0743	0.1270

Table 2-10. Main Solid Fuel-Fired Boiler—Metallic Hazardous Air Pollutant Emission Rates (Continued, Page 2 of 2)

Pollutant	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke*†	Case 4 LA/Petcoke	Case 5 CA/Petcoke†‡	
Maximum heat input	MMBtu/hr	7,333	7,432	7,475	7,383	7,320	7,475
Fuel ash fraction (A)	%/100	0.1404	0.0850	0.0441	0.0678	0.1222	0.1404
Controlled PM emission rate (PM)	lb/MMBtu	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130
Maximum fuel consumption	ton/hr	299	336	377	316	293	377
Emission factor	lb/MMBtu*†	$a \times (C / A \times PM)^b$; Table 1.1-16, AP-42, EPA, September 1998.					
Manganese (Mn)	C (ppmw)	20.19	N/A	49.85	N/A	20.19	49.85
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb/MMBtu*†	5.261		30.034		5.261	
	lb/hr	0.0386		0.2245		0.0386	0.2245
	tpy	0.1690		0.9833		0.1690	0.9833
Nickel (Ni)	C (ppmw)	14.88	N/A	64.20	N/A	71.91	71.91
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb/MMBtu*†	4.065		37.193		4.065	
	lb/hr	0.0298		0.2780		0.0298	0.2780
	tpy	0.1306		1.2177		0.1306	1.2177
Selenium (Se) uncontrolled control efficiency	C (ppmw)	3.58	N/A	0.94	N/A	3.58	3.58
	lb/hr	2.14		0.71		2.10	
	%	90.00		90.00		90.00	
	lb/hr	0.2142		0.0706		0.2099	0.2142
	tpy	0.9383		0.3091		0.9195	0.9383
Vanadium (V)	C (ppmw)	19.21	N/A	163.02	N/A	165.37	165.37
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb/MMBtu*†	5.043		81.742		5.043	
	lb/hr	0.0370		0.6110		0.0370	0.6110
	tpy	0.1620		2.6763		0.1620	2.6763

Note: N/A = not available.

C = average fuel concentration from USGS National Coal Resources Data System, US Coal Quality Database;
<http://energy.er.usgs.gov/products/databases/coalqual/intro.htm>.

*Metal concentrations reflect 100-percent PRB except for nickel and vanadium.

†Metal concentrations for nickel and vanadium based on 70/30-percent PRB/petcoke blend.

‡Metal concentrations reflect 100-percent CA except for nickel and vanadium.

Sources: S&L, 2007.
 ECT, 2007.

Table 2-11. Auxiliary Boiler—Criteria Pollutant Emission Rates

Pollutant	Units	Value
Operating hours	hr/yr	876
Heat input (100-percent load)	10 ⁶ Btu/hr (HHV)	375
NO _x	lb/10 ⁶ Btu	0.09
	tpy	14.8
	lb/hr	33.8
	g/s	4.3
SO ₂	lb/10 ⁶ Btu	0.0016
	tpy	0.3
	lb/hr	0.60
	g/s	0.075
CO	lb/10 ⁶ Btu	0.08
	tpy	13.1
	lb/hr	30.0
	g/s	3.8
VOC	lb/10 ⁶ Btu	0.0054
	tpy	0.89
	lb/hr	2.0
	g/s	0.26
PM/PM ₁₀	lb/10 ⁶ Btu	0.023
	tpy	3.78
	lb/hr	8.6
	g/s	1.09
Lead	lb/10 ⁶ Btu	9.00E-06
	tpy	1.48E-03
	lb/hr	3.38E-03
	g/s	4.25E-04

Sources: S&L, 2007.
ECT, 2007.

Table 2-12. Emergency Generator Diesel Engine—Criteria Pollutant Emission Rates

Pollutant	Units	Value
Operating hours	hr/yr	96*
Generator output	kW	1,640
(100-percent load)	hp	2,309
NO _x	g/kW-hr	6.0
	tpy	1.0
	lb/hr	21.7
	g/s	2.7
SO ₂	g/kW-hr	0.0079
	tpy	0.0014
	lb/hr	0.029
	g/s	0.0036
CO	g/kW-hr	3.5
	tpy	0.61
	lb/hr	12.7
	g/s	1.6
VOC	g/kW-hr	0.40
	tpy	0.069
	lb/hr	1.4
	g/s	0.18
PM/PM ₁₀	g/kW-hr	0.20
	tpy	0.035
	lb/hr	0.72
	g/s	0.09
Lead	g/kW-hr	Negligible
	tpy	Negligible
	lb/hr	Negligible
	g/s	Negligible

Note: g/kW-hr = gram per kilowatt-hour.

*Excluding operation during emergency conditions.

Sources: S&L, 2007.
ECT, 2007.

Table 2-13. Emergency Firewater Pump Diesel Engine—Criteria Pollutant Emission Rates

Pollutant	Units	Value
Operating hours	hr/yr	96*
Engine Output (100-percent load)	hp	432
NO _x	g/hp-hr	2.0
	tpy	0.09
	lb/hr	1.9
	g/s	0.24
SO ₂	g/hp-hr	0.0054
	tpy	0.0002
	lb/hr	0.0051
	g/s	0.0006
CO	g/hp-hr	2.6
	tpy	0.12
	lb/hr	2.5
	g/s	0.3
VOC	g/hp-hr	1.0
	tpy	0.046
	lb/hr	1.0
	g/s	0.12
PM/PM ₁₀	g/hp-hr	0.15
	tpy	0.0069
	lb/hr	0.14
	g/s	0.02
Lead	g/hp-hr	Negligible
	tpy	Negligible
	lb/hr	Negligible
	g/s	Negligible

*Excluding operation during emergency conditions.

Sources: S&L, 2007.
ECT, 2007.

Table 2-14. Cooling Tower and Material Handling/Storage—Annual PM/PM₁₀ Emission Rates

Source	Annual Emission Rates	
	PM (tpy)	PM ₁₀ (tpy)
Cooling tower	73.40	1.13
Solid fuel handling	5.58	4.59
Limestone handling	0.86	0.43
Fly ash handling	1.20	1.19
Gypsum handling	0.13	0.06
Storage pile activities	1.07	0.58
Storage pile wind erosion	0.18	0.06
Paved roads	27.37	5.33
Totals	109.79	13.37

Sources: S&L, 2007.
ECT, 2007.

Table 2-15. Construction-Related Emission Rate Summary

Criteria Pollutant	Estimated Annual Emissions (tpy)					Project Totals
	Soil Transfer and Fill	Grading Activities	Traffic on Unpaved Roads	Wind Erosion	Heavy Equipment Diesel Engines	
NO _x	N/A	N/A	N/A	N/A	107.48	107.5
CO	N/A	N/A	N/A	N/A	36.20	36.2
VOC	N/A	N/A	N/A	N/A	7.18	7.2
SO ₂	N/A	N/A	N/A	N/A	0.04	0.04
PM ₁₀	0.44	3.18	74.10	0.47	6.45	84.6
Lead	N/A	N/A	N/A	N/A	Negligible	0.00

Note: N/A = not applicable.

Sources: S&L, 2007.
ECT, 2007.

Table 2-16. Annual Criteria Pollutant Emission Rate Summary

Criteria Pollutant	Potential Annual Emissions (tpy)						Project Totals
	Main Boiler*	Auxiliary Boiler	Generator Diesel Engine	Firewater Pump Diesel Engine	Cooling Tower	Material Handling	
NO _x	1,637.0	14.8	1.04	0.09	N/A	N/A	1,652.9
CO	4,911.1	13.1	0.61	0.12	N/A	N/A	4,924.9
VOC	117.9	0.9	0.07	0.05	N/A	N/A	118.9
SO ₂	1,309.6	0.3	Negligible	Negligible	N/A	N/A	1,309.9
PM ₁₀	803.0	3.8	0.03	0.01	1.1	12.3	820.2
Lead	0.13	Negligible	Negligible	Negligible	N/A	N/A	0.13

Note: N/A = not applicable.

*Based on 8,760 hr/yr at 100-percent load. Annual emissions including shutdown, maintenance outages, and startups will be lower.

Sources: S&L, 2007.
ECT, 2007.

Table 2-17. Annual Hazardous Air Pollutant Emission Rate Summary

Hazardous Air Pollutant	Potential Annual Emissions (tpy)				Project Totals
	Main Boiler	Auxiliary Boiler	Generator Diesel Engine	Firewater Pump Diesel Engine	
<u>Organic HAPS</u>					
1,1,1-Trichloroethane	0.0330	2.83E-04			0.0333
2,4-Dinitrotoluene	0.0005				0.0005
2-Chloroacetophenone	0.0116				0.0116
Acetaldehyde	0.0116		6.72E-04	1.23E-04	0.0124
Acetophenome	0.0248				0.0248
Acrolein	0.4789		8.10E-05	1.48E-05	0.4790
Benzene	2.1466	2.57E-04	8.17E-04	1.49E-04	2.1479
Benzyl Chloride	1.1559				1.1559
Bis(2-ethylhexyl)phthalate (DEHP)	0.1205				0.1205
Bromoform	0.0644				0.0644
Carbon disulfide	0.2147				0.2147
Chlorobenzene	0.0363				0.0363
Chloroform	0.0974				0.0974
Cumene	0.0088				0.0088
Cyanide	4.1282				4.1282
Dibenzofurans (total PCDD/PCDF)	0.0000029				0.0000
Dimethyl sulfate	0.0793				0.0793
Ethyl benzene	0.1552	7.63E-05			0.1553
Ethyl chloride	0.0694				0.0694
Ethylene dibromide	0.0020				0.0020
Ethylene dichloride	0.0661				0.0661
Formaldehyde	0.3963	3.96E-02	1.03E-03	1.89E-04	0.4371
Hexane	0.1106				0.1106
Isophorone	0.9577				0.9577
Methyl bromide	0.2642				0.2642
Methyl chloride	0.8752				0.8752
Methyl ethyl ketone	0.6440				0.6440
Methyl hydrazine	0.2807				0.2807
Methyl methacrylate	0.0330				0.0330
Methyl tert-butyl ether	0.0578				0.0578
Methylene chloride	0.4789				0.4789
Naphthalene	0.0215	1.35E-03			0.0228
Phenol	0.0264				0.0264
Polycyclic aromatic hydrocarbons	0.0315	7.26E-05	1.47E-04	2.69E-05	0.0317
Propionaldehyde	0.6275				0.6275
Styrene	0.0413				0.0413
Tetrachloroethylene	0.0710				0.0710
Toluene	0.3963	7.43E-03	3.58E-04	6.54E-05	0.4042
Vinyl acetate	0.0125				0.0125
Xylenes	0.0611	1.31E-04	2.50E-04	4.56E-05	0.0615
<u>Acid Gases</u>					
HCl	147.7453	4.16E-01			148.1613
HF	15.2995	4.47E-02			15.3442

Table 2-17. Annual Hazardous Air Pollutant Emission Rate Summary (Continued, Page 2 of 2)

Hazardous Air Pollutant	Potential Annual Emissions (tpy)				Project Totals
	Main Boiler	Auxiliary Boiler	Generator Diesel Engine	Firewater Pump Diesel Engine	
<u>Metallic HAPS</u>					
Antimony (Sb)	0.0093				0.0093
Arsenic (As)	0.1811	6.57E-04			0.1818
Beryllium (Be)	0.0318	4.93E-04			0.0323
Cadmium (Cd)	0.0055	4.93E-04			0.0060
Chromium (Cr)	0.1682	4.93E-04			0.1687
Cobalt (Co)	0.0690				0.0690
Lead (Pb)	0.1270	1.48E-03			0.1285
Manganese (Mn)	0.9833	9.86E-04			0.9843
Mercury (Hg)	0.0291	4.93E-04			0.0296
Nickel (Ni)	1.2177	4.93E-04			1.2182
Selenium (Se)	0.9383	2.46E-03			0.9408
Vanadium (V)	2.6763				2.6763
					0.0000
Totals	183.7740	0.5180	0.0034	0.0004	184.2956

Sources: S&L, 2007.
ECT, 2007.

Table 2-18. Main Boiler Stack Parameters

Parameter	Units	Fuel Type				
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke
Height above grade	ft meter	550 167.6	550 167.6	550 167.6	550 167.6	550 167.6
Exit diameter	ft meter	30.8 9.39	30.8 9.39	30.8 9.39	30.8 9.39	30.8 9.39
Stack area	ft ²	745.1	745.1	745.1	745.1	745.1
Flow rate	acfm	2,305,150	2,461,486	2,355,639	2,413,491	2,301,126
Exit velocity	ft/sec m/sec	51.6 15.7	55.1 16.8	52.7 16.1	54.0 16.5	51.5 15.7
Exit temperature	°F K	130.0 327.6	130.0 327.6	130.0 327.6	130.0 327.6	130.0 327.6

Sources: S&L, 2007.
ECT, 2007.

Table 2-19. Auxiliary Boiler, Emergency Diesel Engines, and Cooling Tower Stack Parameters

Parameter	Units	Emission Source			
		Auxiliary Boiler	Generator Diesel Engine	Firewater Pump Diesel Engine	Cooling Tower*
Height above grade	ft	200	20	12	60
	meter	61.0	6.1	3.7	18.3
Exit diameter	ft	7.0	1.3	0.5	32.5
	meter	2.13	0.38	0.15	9.91
Stack area	ft ²	38.5	1.2	0.20	829.6
Flow rate	acfm	159,131	9,688	1,752	1,283,189
Exit velocity	ft/sec	68.9	131.6	148.7	25.8
	m/sec	21.0	40.1	45.3	7.9
Exit temperature	°F	595.0	855.0	845.0	100.8
	K	585.9	730.4	724.8	311.4

*Per cell.

Sources: S&L, 2007.
ECT, 2007.

2.5 EXCESS EMISSIONS

The TEC main boiler may have up to approximately 12 startups per year due to forced and unforced outages. The duration of each startup will depend on the temperatures of the main boiler and steam turbine following the outages. The main boiler wet FGD and WESP control systems will be in service throughout the startup cycle. However, the SCR control system cannot be placed in service until the boiler flue gas temperature reaches the minimum SCR catalyst operating temperature. Similarly, the fabric filter internal bypass will be in use until solid fuel firing comprises at least 20 percent of the total ULSD fuel oil/coal heat input to prevent blinding of the filter bags. A portion of the main boiler startups will involve up to 14 hours of ULSD fuel firing, during which time excess emissions may result for some pollutants (i.e., NO_x, CO, and VOC). Excess emissions will occur until the main boiler attains a steady-state generation load of approximately 35 percent when firing solid fuels, at which time the unit will be in compliance with all proposed emission limits. TEC estimates approximately 110 hr/yr of excess emissions due to startup events. Hourly mass (i.e., lb/hr) emission rates during startup events for all pollutants with short-term ambient air quality standards (AAQS) (i.e., SO₂, PM₁₀, and CO) will all be lower than the rates that will occur at 100-percent load. Table 2-20 provides a summary of estimated startup emissions for the main boiler.

Unless specifically authorized by FDEP for a longer duration, Rule 62-210.700(1), F.A.C., allows excess emissions for up to 2 hours in any 24-hour period provided best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized. TEC will be a base load unit with an estimated capacity factor of 90 percent. The frequency of unit startups will therefore be low. Each unit startup will also be preceded by an outage; during the outage period, there will be no emissions from the main boiler. Startups of the TEC main boiler will be conducted using best operational practices to minimize emissions and duration consistent with process and safety considerations. TEC estimates up to 14 hours of excess emissions per startup. Accordingly, allowances for excess emissions during startups for up to 14 hours in any 24-hour period, and for up to 110 hours on an annual basis, are requested.

Table 2-20. Main Boiler—Cold Startup Emissions*

Pollutant	Units	Value
Number of startups	Annual	12
Duration of startups	hr/yr	110
NO _x	lb/hr (average) tpy	597.2 32.2
SO ₂	lb/hr (average) tpy	54.3 2.9
CO	lb/hr (average) tpy	681.5 36.8
VOC	lb/hr (average) tpy	30.2 1.6
PM/PM ₁₀	lb/hr (average) tpy	31.3 1.7

*Emissions from initial firing to steady-state operation at 35-percent load firing solid fuels.

Sources: S&L, 2007.
ECT, 2007.

3.0 NEW SOURCE REVIEW REQUIREMENTS

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act (CAA) Amendments (1990), the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary national ambient air quality standards (NAAQS) for six air pollutants (Chapter 40, Part 50, Code of Federal Regulations [CFR]). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also adopted AAQS (reference Section 62-204.240, Florida Administrative Code [F.A.C.]). Table 3-1 presents the current national and Florida AAQS.

Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. The TEC Project will be located in east-central Taylor County approximately 5 miles southeast of the city of Perry. Taylor County is presently designated in 40 CFR 81.310 as better than national standards (for total suspended particulates [TSPs], sulfur dioxide [SO₂], and nitrogen dioxide [NO₂]), unclassifiable/attainment (for carbon monoxide [CO], 8-hour ozone, and particulate matter less than or equal to 2.5 micrometers (PM_{2.5}), and not designated (for lead). Taylor County is designated attainment (for ozone, SO₂, CO, and NO₂) and unclassifiable (for particulate matter less than or equal to 10 micrometers [PM₁₀] and lead) by Section 62-204.340, F.A.C.

Although the Florida rules currently include a 1-hour ozone AAQS (reference Rule 62-204.240[4], F.A.C.), on the federal level EPA revoked this standard in Florida effective June 15, 2005. FDEP plans to adopt both the 8-hour ozone and PM_{2.5} NAAQS, and remove the 1-hour ozone AAQS in a single rulemaking project. This future FDEP rulemaking project is anticipated to begin in the fall of 2007 following EPA's planned adoption of a PM_{2.5} New Source Review (NSR) rule in the summer of 2007.

Table 3-1. National and Florida Air Quality Standards (micrograms per cubic meter [$\mu\text{g}/\text{m}^3$] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards		Florida Standards
		Primary	Secondary	
SO_2	3-hour ¹		1,300	1,300
	24-hour ¹	365		260
	Annual ²	80		60
PM_{10}	24-hour ³	150	150	150
	Annual ⁴			50
$\text{PM}_{2.5}$	24-hour ⁵	35	35	
	Annual ⁶	15	15	
CO	1-hour ¹	40,000		40,000
	8-hour ¹	10,000		10,000
Ozone (ppmv)	1-hour ⁷			0.12
	8-hour ⁸	0.08	0.08	
NO_2	Annual ²	100	100	100
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

¹Not to be exceeded more than once per calendar year.

²Arithmetic mean.

³The standards are attained when the expected number of days per calendar year with a 24-hour average concentration above $150 \mu\text{g}/\text{m}^3$, as determined in accordance with 40 CFR 50 Appendix K, is equal to or less than one.

⁴The standards are attained when the expected annual arithmetic mean concentration, as determined in accordance with 40 CFR 50 Appendix K, is less than or equal to $50 \mu\text{g}/\text{m}^3$.

⁵98th percentile concentration, as determined in accordance with 40 CFR 50 Appendix N.

⁶Arithmetic mean concentration, as determined in accordance with 40 CFR 50 Appendix N.

⁷Standard attained when the expected number of calendar days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H.

⁸Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentrations over a 3-year period are less than or equal to the standard, as determined by 40 CFR 50, Appendix I.

Sources: 40 CFR 50.

Section 62-204.240, F.A.C.

3.2 NONATTAINMENT NSR APPLICABILITY

The TEC Project will be located in Taylor County. As noted previously, Taylor County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, the TEC Project is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The TEC Project will have potential emissions greater than 100 tons per year (tpy) of a Prevention of Significant Deterioration (PSD) pollutant and is one of the named major stationary source categories (i.e., fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour [MMBtu/hr]) listed in Section 169 of the CAA and Rule 62-210.200(193)(a)1., F.A.C. Accordingly, the TEC Project will be classified as a *major facility* subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels. Comparisons of estimated potential annual emission rates for the TEC Project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of nitrogen oxides (NO_x), CO, particulate matter (PM), PM₁₀, SO₂, volatile organic compounds (VOC), total fluorides, and sulfuric acid mist (SAM) are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Appendix A provides detailed emission rate estimates for the TEC Project.

3.4 PSD REQUIREMENTS

3.4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(4)(c), F.A.C., an analysis of best available control technology (BACT) is required for each pollutant emitted by the TEC Project in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(40), F.A.C., BACT is:

“an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account: (1) energy, environmental, and economic impacts, and other costs, (2) all scientific, engineering, and technical material and other information available to the Department, and (3) the

Table 3-2. Projected TEC Emissions Compared to PSD Significant Emission Rates

Pollutant	Projected Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO _x	1,653	40	Yes
CO	4,925	100	Yes
PM (filterable)	539	25	Yes
PM ₁₀ (filterable and condensable)	820	15	Yes
SO ₂	1,310	40	Yes
Ozone/VOC	119	40	Yes
Lead	0.13	0.6	No
Mercury	0.029	0.1	No
Total fluorides	15	3	Yes
H ₂ SO ₄ mist	131	7	Yes
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor acid gases (measured as SO ₂ and hydrogen chloride)	Not present	40	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^{-6}	No
For the pollutants listed above, and for major stationary sources locating within 10 km of a Class I area having an impact equal to or greater than 1 µg/m ³ , 24-hour average	N/A	Any amount	No

Sources: Rule 62-210.200(277), F.A.C.
 ECT, 2007.
 S&L, 2007.

emission limiting standards or BACT determinations of Florida and any other state, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.”

BACT determinations are made on a case-by-case basis as part of the Florida Department of Environmental Protection (FDEP) NSR process and apply to each pollutant that exceeds the PSD significant emission rate thresholds shown in Table 3-2. All emission units, which emit or increase emissions of the applicable pollutants, involved in a major modification or a new major source must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emission units may undergo BACT analysis for more than one pollutant.

BACT is defined in terms of a numerical emissions limit. This numerical emissions limit can be based on the application of air pollution control equipment; specific production processes, methods, systems, or techniques; fuel cleaning; or combustion techniques. BACT limitations may not exceed any applicable federal new source performance standard (NSPS), national emission standard for hazardous air pollutants (NESHAPs), or any other emission limitation established by state regulations.

BACT analyses must be conducted using the following five step *top-down* approach:

1. All available control technology alternatives are identified based on knowledge of the particular industry of the applicant, control technology vendors, technical journals and reports, and previous control technology permitting decisions for other identical or similar sources.
2. The identified available control technologies are evaluated for technical feasibility. If a control technology has been installed and operated successfully on the type of source under review, it is considered demonstrated and technically feasible. An undemonstrated control technology may be considered technically feasible if it is available and applicable. A control technology is considered available if it can be obtained commercially (i.e., the technology has reached the licensing and commercial sales phase of development). An

available control technology is applicable if it can reasonably be installed and operated on the source type under consideration. Undemonstrated available control technologies that are determined to be technically infeasible, based on physical, chemical, and engineering principals, are eliminated from further consideration.

3. The technically feasible technology alternatives are rank-ordered by stringency into a control technology hierarchy.
4. The hierarchy is evaluated starting with the *top*, or most stringent alternative, to determine economic, environmental, and energy impacts and to assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is accepted as BACT from an economic and energy standpoint, evaluation of energy and economic impacts is not required since the only reason for conducting these assessments is to document the rationale for rejecting an alternative technology as BACT. Instead, the applicant proceeds to evaluate the top case control technology for impacts of unregulated air pollutants or impacts in other media (i.e., collateral environmental impacts). If there are no issues regarding collateral environmental impacts, the BACT analysis is complete, and the top case control technology alternative is proposed as BACT. If the top control alternative is not applicable due to adverse energy, environmental, or economic impacts, it is rejected as BACT and the next most stringent control alternative is then considered.
5. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emission level corresponding to BACT for the evaluated pollutant.

This five-step procedure for conducting a BACT analysis is described in Chapter B of EPA's Draft New Source Review Manual dated October 1990.

The BACT emission limit established during the initial permitting process will be enforceable over the life of the unit. As a result, the BACT analysis must take into account the full range of possible fuels, operating conditions, operating system fluctuations, and normal wear-and-tear on the units and control systems. EPA's Environmental Appeals Board (EAB) has recognized that "permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow permittees to achieve compliance on a consistent basis" (Three Mountain Power, PSD Appeal No. 01-05 at 21 [May 30, 2001] citing: *In re Masonite Corp.*, 5 E.A.D. 560-61 [EAB 1994] ["There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor."]; and *In re Knauf Fiber Glass, GmbH*, PSD Appeal Nos. 99-8 to -72, slip op. at 21 [EAB, Mar. 14, 2000] ["The inclusion of a reasonable safety factor in the emission limitation is a legitimate method of deriving a specific emission limitation that may not be exceeded."]).

3.4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(7), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those which the source would potentially emit in significant amounts (i.e., those that exceed the PSD significant emission rate thresholds shown in Table 3-2).

Preconstruction ambient air monitoring for a period of up to 1 year is generally required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance (QA) requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided by EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (1987a).

Rule 62-212.400(3)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility will be exempt from the monitoring requirements of

Rule 62-212.400(7), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the new source would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400(3)(e)1., F.A.C. (see Table 3-3). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Applicability of the PSD preconstruction ambient monitoring requirements to the TEC Project is discussed in Section 8.2.

3.4.3 AMBIENT IMPACT ANALYSIS

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates (see Table 3-2). The FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220[4], F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA *Guideline on Air Quality Models* (GAQM) as published in Appendix W to 40 CFR 51. Criteria pollutants may be exempt from the full source impact analysis if the net increase in impacts due to the new source or modification is below the appropriate Rule 62-210.200(278), F.A.C., significant impact level (SIL), as presented in Table 3-4. EPA has proposed SILs for Class I areas – these levels are provided in Table 3-5.

Ozone is one pollutant for which a source impact analysis is not normally required. Ozone is formed in the atmosphere as a result of complex photochemical reactions. Models for ozone generally are applied to entire urban areas.

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of the highest of the second-highest (HSH) short-term concentrations for comparison to AAQS or PSD increments. The term *highest, second-highest* refers to the highest of the second-highest

Table 3-3. PSD *De Minimis* Ambient Impact Levels

Averaging Time	Pollutant	<i>De Minimis</i> Level ($\mu\text{g}/\text{m}^3$)
Annual	NO ₂	14
Quarterly	Lead	0.1
24-Hour	PM ₁₀	10
	SO ₂	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Total reduced sulfur	10
	Hydrogen sulfide	0.2
	Reduced sulfur compounds	10
NA	Ozone	100 tpy of VOC emissions

Source: Rule 62-212.400(3)(e)1., F.A.C.

Table 3-4. FDEP Significant Impact Levels

Pollutant	Averaging Period	Concentration ($\mu\text{g}/\text{m}^3$)
SO ₂	Annual	1
	24-Hour	5
	24-Hour (Class I Areas)	1
	3-Hour	25
PM ₁₀	Annual	1
	24-Hour	5
	24-Hour (Class I Areas)	1
NO ₂	Annual	1
CO	8-Hour	500
	1-Hour	2,000
Lead	Quarterly	0.03

Source: Rule 62-210.200(278), F.A.C.

Table 3-5. EPA Significant Impact Levels—Class I Areas

Pollutant	Averaging Period	Concentration ($\mu\text{g}/\text{m}^3$)
SO ₂	Annual	0.1
	24-Hour	0.2
	3-Hour	1.0
PM ₁₀	Annual	0.2
	24-Hour	0.3
NO ₂	Annual	0.1

Source: EPA Proposed, 1996; 61FR 38249.

concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term PSD increments specify the standard should not be exceeded at any location more than once per year. If less than 5 years of meteorological data are used, the highest concentration at each receptor must be used.

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level for SO₂ and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the area in which a new source (or modification) will have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 2,024 hectares [ha] [5,000 acres], and national parks larger than 2,428 ha [6,000 acres]) or Class II (all other areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. However, the states were given the authority to redesignate any Class II area to Class III status, provided certain requirements were met. EPA then promulgated, as regulations, the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated PSD increments for NO₂; the effective date of the new regulation was October 17, 1989. However, the baseline date for NO₂ increment consumption was set at February 8, 1988; new major sources or modifications constructed after this date will consume NO₂ increment.

On June 3, 1993, EPA promulgated PSD increments for PM₁₀; the effective date of the new regulation was June 3, 1994. The increments for PM₁₀ replace the original PM increments that were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM₁₀ increments. Revised NAAQS for PM, which include revised NAAQS for PM₁₀ and PM_{2.5}, became effective on October 17, 2006. Due to the significant technical difficulties that exist with

respect to PM_{2.5} monitoring, emissions estimation, and modeling, EPA has determined that implementation of PSD permitting for PM_{2.5} is administratively impracticable at this time for state permitting authorities. Accordingly, EPA has advised that PM₁₀ may be used as a surrogate for PM_{2.5} in meeting NSR requirements until these difficulties are resolved.

Current Florida PSD allowable increments are specified in Section 62-204.260, F.A.C., and shown on Table 3-6.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended, *baseline concentration* means the ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established based on:

- The actual emissions representative of sources in existence on the applicable minor source baseline date.
- The allowable emissions of major stationary sources that commenced construction before the major source baseline date but were not in operation by the applicable minor source baseline date.

The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s) (i.e., allowed increment consumption):

- Actual emissions from any major stationary source on which construction commenced after the major source baseline date.
- Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

It is not necessary to make a determination of the baseline concentration to determine the amount of PSD increment consumed. Instead, increment consumption calculations need only reflect the ambient pollutant concentration *change* attributable to emission sources

Table 3-6. PSD Allowable Increments ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Time	Class		
		I	II	III
PM ₁₀	Annual arithmetic mean	4	17	34
	24-Hour maximum*	8	30	60
SO ₂	Annual arithmetic mean	2	20	40
	24-Hour maximum*	5	91	182
	3-Hour maximum*	25	512	700
NO ₂	Annual arithmetic mean	2.5	25	50

*Maximum concentration not to be exceeded more than once per year at any one location.

Source: Section 62-204.260, F.A.C.

that affect increment. *Major* source baseline date means January 6, 1975, for PM (TSP/PM₁₀) and SO₂ and February 8, 1988, for NO₂. *Minor* source baseline date means the earliest date after the trigger date on which the first complete application was submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21 or Section 62-212.400, F.A.C. The trigger dates are August 7, 1977, for PM (TSP/PM₁₀) and SO₂ and February 8, 1988, for NO₂.

The ambient impact analyses for the TEC Project are provided in Sections 6.0 (Methodology), 7.0 (PSD Class II areas), and 10.0 (PSD Class I areas).

3.4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(8), F.A.C., requires additional impact analyses for three areas: associated growth, soils and vegetation impact, and visibility impairment. The level of analysis for each area should be commensurate with the scope of the project. A more extensive analysis would be conducted for projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

- A projection of the associated industrial, commercial, and residential growth that will occur in the area.
- An estimate of the air pollution emissions generated by the permanent associated growth.
- An air quality analysis based on the associated growth emission estimates and the emissions expected to be generated directly by the new source or modification.

The soils and vegetation analysis is typically conducted by comparing projected ambient concentrations for the pollutants of concern with applicable susceptibility data from the air pollution literature. For most types of soils and vegetation, ambient air concentrations of criteria pollutants below the NAAQS will not result in harmful effects. Sensitive vege-

tation and emissions of toxic air pollutants could necessitate a more extensive assessment of potential adverse effects on soils and vegetation.

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of the project. Section 9.0 provides the additional impact analyses for the TEC Project.

3.5 HAZARDOUS AIR POLLUTANT REQUIREMENTS

Florida relies on the requirements of the CAA with respect to the regulation of hazardous (also known as toxic) air pollutants. These federal requirements include a comprehensive set of technology-based emission standards referred to as NESHAPs. These standards establish hazardous air pollutant emission limitations for a wide variety of industrial source categories. Recent NESHAPs (i.e., those adopted after the 1990 amendments to the CAA) reflect maximum achievable control technology (MACT). Section 4.2 provides a discussion of the NESHAPs program and its applicability to the TEC Project.

4.0 STATE AND FEDERAL EMISSION STANDARDS

4.1 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Section 111 of the CAA, Standards of Performance of New Stationary Sources, requires EPA establish federal emission standards for source categories that cause or contribute significantly to air pollution. These standards are intended to promote use of the best air pollution control technologies, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, EPA has promulgated more than 75 standards. The NSPS are codified in the Code of Federal Regulations at 40 CFR 60.

Major components of the TEC Project include solid fuel transfer, storage, and preparation equipment, a supercritical pulverized solid fuel-fired main boiler, a 20-cell mechanical draft cooling tower, and emission control reagent and combustion byproduct material handling systems. Ancillary equipment includes an auxiliary boiler, an emergency diesel generator, an emergency diesel-driven firewater pump, and an ULSD storage tank. Those NSPS that are applicable to the TEC Project are discussed in the following sections.

4.1.1 NSPS SUBPART Da—ELECTRIC STEAM GENERATING UNITS

The TEC main boiler will have a heat input capacity greater than 250 MMBtu/hr, meets the definition of an *electric utility steam generating unit*, and will commence construction after September 18, 1978. The TEC main boiler will therefore be subject to the applicable requirements of NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. NSPS Subpart Da was amended on February 27, 2006, to include emission standards for steam generating units that commence construction after February 28, 2005.

NSPS Subpart Da specifies emission limitations, monitoring, reporting, and recordkeeping requirements for PM, NO_x, SO₂, and opacity. Applicable NSPS Subpart Da emission standards for the TEC main boiler are summarized as follows:

- PM—0.14 pound per megawatt-hour (lb/MWh) gross energy output or 0.015 pound per million British thermal units (lb/MMBtu). Alternatively, units that commence construction after February 28, 2005, may elect to comply with a PM emission limit of 0.03 lb/MMBtu and a 99.9-percent reduction from uncontrolled emission rates. Opacity is limited to 20 percent (6-minute average), except for one 6-minute period per hour of no more than 27 percent.
- SO₂—1.4 lb/MWh gross energy output on a 30-day rolling average basis, or 95-percent reduction on a 30-day rolling average basis.
- NO_x—1.0 pound per megawatt (lb/MW) gross energy output, on a 30-day rolling average basis.
- Mercury— 20×10^{-6} lb/MWh gross energy output, on a 12-month rolling average basis when firing bituminous coal. When firing subbituminous coal at locations having a mean annual rainfall greater than 25 inches, the emission limit is 66×10^{-6} lb/MWh gross energy output, on a 12-month rolling average basis. These mercury emission standards are prorated based on heat input when firing blends of bituminous and subbituminous coals.
- The NSPS Subpart Da PM, NO_x, and mercury emission limits do not apply during periods of startup, shutdown, or malfunction. The NSPS Subpart Da SO₂ applies at all times except emergency conditions.

The TEC main boiler will be required to install continuous emissions monitor systems (CEMS) for opacity, SO₂, NO_x, and mercury pursuant to 40 CFR 60.49Da(a), (b), (c), and (p) and a CEMS for oxygen or CO₂ pursuant to 40 CFR 60.49Da(d). Initial performance tests will be required to demonstrate compliance with the NSPS Subpart Da PM, opacity, NO_x, and SO₂ emission standards in accordance with the test methods specified in 40 CFR 60.48Da. Subpart Da compliance provisions for PM require the use of opacity monitoring equipment as an indicator of continuous PM control device performance and a continuous bag leak detection system for units equipped with fabric filters. Alternatively, a PM CEMS may be used to demonstrate compliance with the Subpart Da PM standard.

Compliance with the NO_x and SO₂ standards will be determined based on a 30-day rolling average as measured by the NO_x and SO₂ CEMS. Compliance with the mercury standard will be determined on a 12-month rolling average basis as measured by the mercury CEMS.

EPA proposed revisions to NSPS Subpart Da on February 9, 2007. The proposed revisions primarily address compliance and monitoring requirements and do not change the emission standards shown previously.

The TEC Project main boiler will have emissions well below the NSPS Subpart Da emission standards and will comply with the applicable requirements of NSPS Subpart Da.

4.1.2 NSPS SUBPART Db—INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

The TEC auxiliary boiler will have a heat input capacity greater than 100 MMBtu/hr, meets the definition of a *steam generating unit*, and will commence construction after June 19, 1984. The TEC auxiliary boiler will therefore be subject to the applicable requirements of NSPS Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. NSPS Subpart Db was amended on February 27, 2006 to include emission standards for steam generating units that commence construction after February 28, 2005.

NSPS Subpart Db specifies emission limitations, monitoring, reporting, and recordkeeping requirements for PM, NO_x, SO₂, and opacity. Applicable NSPS Subpart Db emission standards for the TEC auxiliary boiler are summarized as follows:

- PM and Opacity—Units that commence construction after February 28, 2005, and that combust only oil containing no more than 0.3 weight percent sulfur are not subject to any PM or opacity emission standard.
- SO₂—Units that commence construction after February 28, 2005, and that combust only oil containing no more than 0.3 weight percent sulfur are not subject to any SO₂ emission standard.

- NO_x—0.20 lb/MMBtu (high heat release rate) on a 24-hour basis (initial performance test) and 3-hour basis (subsequent performance tests) for units that combust only distillate oil and have a capacity factor of 10 percent or less. After February 27, 2006, units may comply with an optional limit of 2.1 lb/MWh gross energy output on a 30-day rolling average basis.
- The NSPS Subpart Db NO_x emission limit applies at all times.

Initial performance tests will be required to demonstrate compliance with the NSPS Subpart Db NO_x emission standard in accordance with the test methods specified in 40 CFR 60.46b. A NO_x CEMS is not required for any unit that combusts only distillate fuel oil and has an annual capacity factor of 10 percent or less pursuant to 40 CFR 60.48b(i).

The TEC Project auxiliary boiler will have emissions well below the NSPS Subpart Db emission standards and will comply with the applicable requirements of NSPS Subpart Db.

4.1.3 NSPS SUBPART Y—COAL PREPARATION PLANTS

NSPS Subpart Y is applicable to coal preparation plants that process more than 200 tons per day of coal and that are constructed after October 24, 1974. Specific facilities addressed by Subpart Y include thermal dryers, pneumatic coal-cleaning equipment, coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems. *Coal preparation plants* are defined as facilities that prepare coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning, and thermal drying.

A detailed description of the TEC Project coal receiving, storage, handling, and crushing process was previously provided in Section 2.3.5. Since the TEC Project will process more than 200 tons per day of coal, the coal processing (including the crusher), conveying, storage, transfer, and loading systems will be subject to the requirements of NSPS Subpart Y.

NSPS Subpart Y, 40 CFR 60.252, contains separate PM standards for: (a) thermal dryers, (b) pneumatic coal cleaning equipment, and (c) coal processing and conveying equipment, coal storage systems, or coal transfer and loading systems. The TEC Project will not include a thermal dryer or pneumatic coal cleaning equipment. Accordingly, visible emissions from the coal processing and conveying equipment (including the crusher), coal storage systems, and coal transfer and loading systems are limited to less than 20-percent opacity as specified by NSPS Subpart Y, 40 CFR 60.252(c). Initial opacity performance tests using EPA Reference Method 9 will be required per the general provisions of NSPS Subpart A, 40 CFR 60.8, and the specific provisions of NSPS Subpart Y, 40 CFR 60.254(a) and (b)(2).

The TEC Project coal handling and processing equipment will comply with the applicable requirements of NSPS Subpart Y.

4.1.4 NSPS SUBPART OOO—NONMETALLIC MINERAL PROCESSING PLANTS

NSPS Subpart OOO is applicable to equipment that processes nonmetallic minerals including crushers, grinding mills, screening operations, bucket elevators, belt conveyors, bagging operations, storage bins, and enclosed truck or railcar loading stations. Limestone will be used at the TEC Project as the reagent for the wet flue gas desulfurization (FGD) system. Limestone is classified as a nonmetallic mineral, and therefore the limestone handling and crushing activities planned for the TEC Project will be subject to the applicable provisions of NSPS Subpart OOO.

NSPS Subpart OOO specifies emission limitations, monitoring, reporting, and record-keeping requirements for PM and opacity. Applicable NSPS Subpart OOO emission standards for the TEC limestone handling and processing equipment are summarized as follows:

PM—0.022 grain per dry standard cubic foot (gr/dscf) and 7-percent opacity for stack emissions (i.e., PM that is released from a capture system), 10-percent opacity for fugitive emissions (i.e., PM that is not collected by a capture system and released to the atmosphere at the point of generation),

and 7-percent opacity from any baghouse that controls emissions from only an individual enclosed storage bin.

Initial compliance with the NSPS Subpart OOO PM emissions standards will be determined using EPA Reference Method 5 or 17 (for stack emissions) and EPA Reference Methods 9 and/or 22 (for opacity determinations). Reporting and recordkeeping requirements are specified in 40 CFR 60.676.

The TEC Project limestone handling and processing equipment will comply with the applicable requirements of NSPS Subpart OOO.

4.1.5 NSPS SUBPART HHHH—EMISSION GUIDELINES AND COMPLIANCE TIMES FOR COAL-FIRED ELECTRIC STEAM GENERATING UNITS

NSPS Subpart HHHH establishes the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State Mercury Budget Trading Program, under Section 111 of the CAA and 40 CFR 60.24(h)(6), as a means of reducing national mercury emissions. Florida has adopted NSPS Subpart HHHH by reference in Section 62-204.800, F.A.C., subject to the provisions set forth at Section 62-296.480, F.A.C. This latter rule provides Florida's implementation of the Federal Clean Air Mercury Rule (CAMR).

The TEC Project will comply with the applicable requirements of NSPS Subpart HHHH.

4.1.6 NSPS SUBPART IIII – STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

NSPS Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the CI ICE are manufactured after April 1, 2006 (and are not fire pump engines), or manufactured after July 1, 2006 (for certified National Fire Protection Association fire pump engines).

NSPS Subpart IIII specifies emission limitations, monitoring, reporting, and recordkeeping requirements for NO_x, CO, nonmethane hydrocarbons (NMHC), and PM. Applicable NSPS Subpart IIII emission standards for the TEC emergency diesel generator and diesel-driven firewater pump CI ICEs are summarized as follows:

- Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in 40 CFR 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.
- Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in Table 4 to NSPS Subpart IIII, for all pollutants.

The TEC emergency generator and firewater pump diesel engines will comply with the applicable requirements of NSPS Subpart IIII.

The ULSD fuel oil storage tank will have a capacity of 300,000 gallons (1,136 cubic meters) and store a liquid with a maximum true vapor pressure less than 0.51 psia (3.5 kilopascals). Accordingly, the ULSD fuel oil storage tank is not subject to NSPS Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*, pursuant to 40 CFR 60.110b(b).

4.2 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPs)

The provisions of the CAA that address the control of hazardous air pollutant (HAP) emissions, or air toxics, are found in Section 112. Section 112 of the CAA includes provisions for the promulgation of NESHAPs, or MACT standards, as well as several related programs to enhance and support the NESHAPs program. Section 112 requires EPA to publish and regularly update (at least every 8 years) a listing of all categories and subcategories of major and area sources that emit HAPs. The Section 112(c) list of source

categories was initially published in the Federal Register on July 16, 1992, and has been periodically revised thereafter. EPA must promulgate regulations establishing emission standards (NESHAPs) for each category or subcategory of major sources and area sources of HAPs that are listed pursuant to Section 112(c). The standards must require the maximum degree of emission reduction that EPA determines to be achievable by each particular source category. Different criteria for MACT apply for new and existing sources. Less stringent standards, known as generally available control technology (GACT) standards, are allowed at the EPA Administrator's discretion for area sources.

On March 29, 2005, EPA issued a final agency action delisting electric utility steam generating units from the CAA Section 112(c) source category list. Instead of regulating electric utility steam generating unit HAP emissions under the NESHAPs program, EPA elected to limit emissions of mercury (the only electric utility steam generating unit HAP considered by EPA to warrant regulation) from coal-fired units using the authority of the NSPS program as described previously in Section 4.1.1 (i.e., NSPS Subpart Da). Accordingly, the TEC Project main boiler is not subject to any 40 CFR 61 or 63 NESHAPs.

Although electric utility steam generating units are no longer included on the Section 112(c) list, the source category list presently includes stationary reciprocating internal combustion engines (RICE) and industrial/commercial/institutional boilers and process heaters. As required by Section 112 of the CAA, EPA promulgated a final NESHAPs for stationary RICE (40 CFR 63, Subpart ZZZZ) on June 15, 2004, and a final NESHAPs for industrial/commercial/institutional boilers and process heaters (40 CFR 63, Subpart DDDDD) on September 13, 2004. The TEC Project will be a major source of HAPs, and, therefore, NESHAPs Subparts ZZZZ and DDDDD are potentially applicable to the TEC emergency diesel engines and auxiliary boiler, respectively.

NESHAPs Subpart ZZZZ applies to new RICE with a site-rating of more than 500 brake horsepower (bhp) that commence construction after December 19, 2002. The TEC emergency diesel-driven firewater pump will have a site-rating of less than 500 bph and therefore will not be subject to the requirements of NESHAPs Subpart ZZZZ. New RICE that operate exclusively as emergency units are subject only to initial notification require-

ments. Accordingly, the TEC emergency generator RICE, which will have a site-rating greater than 500 bhp, will need to comply with the initial notification requirements of 40 CFR 63.6645(d).

The only applicable NESHAPs is Subpart DDDDD, National Emission Standards For Hazardous Air Pollutants For Industrial, Commercial, and Institutional Boilers and Process Heaters. The TEC auxiliary boiler meets the definition of an *industrial boiler* and therefore will be subject to the applicable requirements of NESHAPs Subpart DDDDD. The TEC auxiliary boiler will qualify for the *limited use liquid fuel category* of NESHAPs Subpart DDDDD since the boiler will combust only liquid fuel, will have a rated capacity greater than 10 MMBtu/hr, and will have a federally enforceable annual average capacity factor equal to or less than 10 percent. Applicable NESHAPs Subpart DDDDD emission standards for the TEC limited use liquid fuel category auxiliary boiler are summarized as follows:

- PM—0.03 lb/MMBtu.
- Hydrogen chloride (HCl)—0.0009 lb/MMBtu.
- CO—400 ppm by volume on a dry basis corrected to 3-percent oxygen (3-run average).
- Opacity—Less than or equal to 10-percent opacity (1-hour block average).

New boilers in the limited use liquid fuel category are not required to conduct a performance test to demonstrate compliance with the emission limits and are not required to set and maintain operating limits to demonstrate continuous compliance with the emission limits. Initial compliance must be by submitting a signed statement in the Notification of Compliance Status report required by 40 CFR 63.7545(e) indicating the intent to burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels. To demonstrate continuous compliance with the applicable emission limits, the facility must keep records that demonstrate that they burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels. The facility must also include a signed statement in each semiannual compliance report required in 40 CFR 63.7550, which indicates that only burned liquid fossil fuels, other than residual

oils, were burned either alone or in combination with gaseous fuels, during the reporting period.

The TEC auxiliary boiler will comply with the applicable requirements of NESHAPs Subpart DDDDD.

4.3 ACID RAIN PROGRAM

The overall goal of the acid rain program (ARP) is to achieve significant environmental and public health benefits through reductions in emissions of SO₂ and NO_x, the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

Title IV of the CAA sets a goal of reducing annual SO₂ emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase tightening of the restrictions placed on fossil fuel-fired power plants. Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Phase II, which began in the year 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing more than 2,000 units in all. The program affects existing utility units serving generators with an output capacity of greater than 25 MW and all new utility units.

For SO₂, the ARP introduced an allowance trading system that harnesses the incentives of the free market to reduce pollution. Under this cap-and-trade program, affected existing utility units (i.e., those in operation prior to November 15, 1990) are allocated allowances based on their historical fuel consumption and a specific emission rate. Each allowance permits a unit to emit 1 ton of SO₂ during or after a specified year. For each ton of SO₂ emitted in a given year, one allowance is retired, that is, it can no longer be used. Allowances may be bought, sold, or banked. Anyone may acquire allowances and participate in

the trading system. However, regardless of the number of allowances a source holds, it may not emit at levels that would violate federal or state limits set under Title I of the CAA to protect public health. During Phase II of the program (now in effect), the CAA set a permanent ceiling (or cap) of 8.95 million allowances for total annual SO₂ allowance allocations to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained. New utility units (i.e., those that commence operation on and after November 15, 1990) are not allocated any SO₂ allowances and must obtain such allowances annually from the ARP SO₂ allowance market in amounts equal to their actual SO₂ emission rates.

The CAA also required a 2-million-ton reduction in NO_x emissions by the year 2000. A significant portion of this reduction has been achieved by coal-fired utility boilers that will be required to install low NO_x burner technologies and to meet new emissions standards. The ARP NO_x emission reduction requirements are only applicable to existing utility units (i.e., those in operation prior to November 15, 1990).

The TEC main boiler will be subject to the ARP since it is a *new utility unit* (i.e., will commence operation after November 15, 1990) and will serve a generator that produces electricity for sale. As noted previously, new utility units do not receive any SO₂ allowance allocations. Accordingly, the TEC Project will need to annually obtain SO₂ allowances from the ARP SO₂ allowance market in amounts equal to the main boiler's actual SO₂ emission rates. The NO_x component of the ARP does not apply to new utility units.

4.4 CLEAN AIR INTERSTATE RULE

On March 10, 2005, EPA issued the final Clean Air Interstate Rule (CAIR). The objective of CAIR is to assist states with PM_{2.5} and 8-hour ozone nonattainment areas to achieve attainment by reducing precursor emissions at sources located in 28 states (including Florida) situated upwind of these nonattainment areas. Based on regional dispersion modeling, EPA determined that these 28 upwind states significantly contribute to PM_{2.5} and 8-hour ozone nonattainment in downwind areas. Florida emission sources are projected to significantly contribute to PM_{2.5} nonattainment areas located in Georgia (Macon and

Atlanta) and Alabama (Birmingham) and to an 8-hour ozone nonattainment area in Georgia (Atlanta).

The CAIR reductions of precursor emissions address annual SO₂ and NO_x emissions (for reductions in annual and daily average ambient PM_{2.5} impacts) and ozone season (May through September) NO_x emissions (for reductions in 8-hour average ambient ozone impacts). The SO₂ and NO_x reductions will be implemented by means of a regional two-phase cap-and-trade program. For SO₂, the first cap begins in calendar year 2010 and extends through 2014. For NO_x, the first cap begins in calendar year 2009 and also extends through 2014. The second phase cap for both pollutants becomes effective in calendar year 2015 and thereafter. The SO₂ caps will reduce current ARP SO₂ emissions by 50 percent in Phase I and by 65 percent in Phase II. The NO_x caps reflect NO_x emission rates of 0.15 and 0.125 lb/MMBtu for the first and second phase caps, respectively.

For each phase cap, CAIR assigns SO₂ and NO_x emission budgets (in units of tpy) and in units of tons per ozone season) to each affected upwind state. These state emission budgets were developed by EPA based on the application of cost-effective control technologies (i.e., FGD) for SO₂ and selective catalytic reduction (SCR) for NO_x. The affected states were required to submit revised state implementation plans (SIPs) within 18 months (i.e., by September 11, 2006) for EPA review and approval. Florida's proposed SIP revisions implementing CAIR were submitted to EPA Region 4 on March 16, 2007, for review and approval in accordance with EPA's abbreviated SIP approval process. The SIPs will provide details as to the procedures that will be used to allocate the state NO_x and SO₂ budgets to individual sources.

Following SIP approval and allocation of the state SO₂ and NO_x budgets to individual emission sources, emission units at these sources must possess sufficient SO₂ and NO_x allowances such that actual emissions (as measured by CEMS) do not exceed the allocations for each control period beginning in 2009 (for NO_x) and 2010 (for SO₂). Sources that have actual emissions in excess of their allocation will need to reduce actual emission rates or purchase additional allowances on the open market. Emission sources that have surplus allow-

ances may bank the allowances for use in any future control period or sell the surplus allowances on the open market.

Florida has adopted EPA's 40 CFR 96 CAIR NO_x and SO₂ Trading Programs for State Implementation Plans by reference in Section 62-204.800, F.A.C. Florida's implementation of the Federal CAIR is set forth at Section 62-296.470, F.A.C.

EPA's model NO_x trading program includes provisions for allocating NO_x allowances to new utility units (those that are placed in service in 2001 or later) such as the TEC main boiler (i.e., a new source set-aside). Similar to the ARP, there are no provisions for a new source set-aside with respect to CAIR SO₂ allowances. For NO_x allowances, new units will be allocated allowances from the new source set-aside until they have established a baseline and are included in the shared pool. NO_x allowance allocations from the new source set-aside pool will be made to new utility units on a pro-rata basis.

4.5 CLEAN AIR MERCURY RULE

On March 15, 2005, EPA issued the final Clean Air Mercury Rule (CAMR). The purpose of CAMR is to reduce national coal-fired power plant mercury emissions from the current level of 48 to 15 tpy by means of a two-phase cap-and trade program. The first phase national mercury cap (with a cap of 38 tpy) becomes effective in 2010 while the second 15-tpy cap becomes effective in 2018 and thereafter.

CAMR also establishes stack mercury emission standards applicable to new sources (i.e., those constructed, modified, or reconstructed after January 30, 2004.) The electric utility steam generating unit stack mercury emissions applicable to the TEC main boiler (i.e., the NSPS Subpart Da mercury emission standards) were previously discussed in Section 4.1.1.

Similar to CAIR, CAMR assigns mercury budgets (in units of tpy) to each state for each phase cap. The first phase mercury cap represents the cobenefits that will be achieved by CAIR (i.e., installation of FGD and SCR controls). The second phase mercury cap is based on the cumulative effect of FGD/SCR cobenefits and on EPA projections regarding

the availability and removal efficiency of future mercury controls (e.g., activated carbon injection [ACI]).

The NSPS program serves as the regulatory authority for CAMR. Accordingly, the revisions to NSPS Subpart Da were effective upon proposal (i.e., January 30, 2004). CAMR also includes a new NSPS, Subpart HHHH, which contains EPA's model mercury trading program. Under the terms of revised NSPS Subpart Da, states must submit plans by November 17, 2006, that address the state EGU mercury caps for 2010 and 2018 for EPA review and approval. The state plans will provide details as to the procedures that will be used to allocate the state mercury budgets to individual coal-fired utility units. For each control period, sufficient mercury allowances must be held to cover the actual mercury emissions for all mercury budget units at a source. Although mercury allowances will be allocated on a unit-by-unit basis, compliance with the CAMR mercury allowance program is determined on a plant-wide basis.

As described previously for the CAIR state SO₂ and NO_x budgets, following SIP approval and allocation of the state mercury budgets to individual emission sources, these sources must possess sufficient mercury allowances to cover their actual emission rates (as continuously measured either by CEMS or sorbent trap monitoring systems) for each control period beginning in 2010. Emission sources that have actual mercury emissions in excess of their allocation will need to reduce actual emission rates or purchase additional allowances. Emission sources that have surplus allowances may bank the allowances for use in any future control period or sell the surplus allowances. Revised SIPs that address the CAMR requirements were required to be submitted to EPA by November 17, 2006.

Florida has adopted NSPS Subpart HHHH by reference in Section 62-204.800, F.A.C., subject to the provisions set forth at Section 62-296.480, F.A.C. This latter rule provides Florida's implementation of the Federal CAMR. Florida's proposed SIP revisions implementing CAMR were submitted to EPA Region 4 on December 29, 2006. Because a portion of these proposed rules were challenged, the CAMR Federal Implementation Plan (FIP) is applicable until the challenge is resolved and Florida's CAMR SIP approved by EPA.

In summary, the TEC main boiler will need to comply with the NSPS Subpart Da stack mercury emission limits for new electric utility steam generating units as well as the mercury cap-and-trade program in accordance with Section 62-296.480, F.A.C.

4.6 FLORIDA EMISSION STANDARDS

FDEP emission standards for stationary sources are contained in Chapter 62-296, Stationary Sources—Emission Standards, F.A.C. General pollutant emission limit standards are included in Section 62-296.320, F.A.C. Sections 62-296.401 through 62-296.417, F.A.C., specify emission standards for 17 categories of sources. Sections 62-296.470 and 62-296.480 address CAIR and CAMR requirements, respectively. Sections 62-296.500 through 62-296.570, F.A.C., establish reasonably available control technology (RACT) requirements for VOC and NO_x emitting facilities. RACT requirements for lead and PM are found in Sections 62-296.600 through 62-296.605 and 62-296.700 through 62-296.712, F.A.C., respectively.

With respect to the TEC Project, the general Rule 62-296.320(4)(b), F.A.C., visible emission limitation of 20-percent opacity will apply to all point (i.e., stack) emission sources. Reasonable precautions to prevent unconfined PM emissions (e.g., coal storage piles) will be required pursuant to Rule 62-296.320(4)(c), F.A.C.

Section 62-296.405, Fossil Fuel Steam Generators with More Than 250 MMBtu/hr Heat Input, F.A.C., will apply to the TEC main and auxiliary boilers. This section requires compliance with applicable NSPS requirements (e.g., NSPS Subpart Da). None of the remaining emission standards specified in Sections 62-296.401 through 62-296.417, F.A.C., are applicable to the TEC Project. The VOC, NO_x, lead, and PM RACT requirements do not apply to emission units that are subject to NSR permitting and therefore are not applicable to the TEC Project.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method. As previously described in Section 3.4.1, the top-down methodology consists of the following five steps:

- Step 1—Identify all available control technologies for each PSD pollutant subject to review.
- Step 2—Eliminate all technically infeasible control technologies.
- Step 3—Rank the remaining control technologies by control effectiveness.
- Step 4—Evaluate the feasible control technologies, beginning with the most efficient, with respect to economic, energy, and environmental impacts.
- Step 5—Select as BACT the most effective control technology that is not rejected based on adverse economic, environmental, and/or energy impacts.

The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, postprocess stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives included:

- EPA reasonably available control technology (RACT)/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC Information system database.
- Recent permits for pulverized coal-fired power projects.
- FDEP BACT determinations for similar facilities.
- Environmental Consulting & Technology, Inc. (ECT), experience for similar projects.

Following the identification of available control technologies, the next step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the EPA NSR Workshop Manual

(EPA, 1990a). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

If the top-case control technology with the highest removal efficiency is selected as BACT, an assessment of collateral environmental impacts is conducted to determine whether such impacts would deem the control technology unacceptable. If the most efficient control technology is not selected as BACT, an assessment of energy, environmental, and economic impacts is then performed. If assessed, the economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual, Sixth Edition (EPA, 2002).

The fifth and final step is the selection of a BACT emission limitation corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

As defined by Rule 62-210.200(40), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR 60), NESHAP (40 CFR 61 and 63), and FDEP emission standards (Chapter 62-296, Stationary Sources—Emission Standards, F.A.C.). The NSPS, NESHAPs, and Florida emission standards applicable to TEC were previously discussed in Sections 4.1, 4.2, and 4.6, respectively. All of the BACT emission limitations proposed for TEC are more stringent than the applicable federal and state standards cited in these sections.

As shown in Table 3-2 of Section 3.3, annual TEC emissions of NO_x, CO, VOC, PM/PM₁₀, SO₂, H₂SO₄ mist, and fluorides are projected to exceed the PSD significance rates for these pollutants. A BACT analysis is therefore required for each TEC emission source that will emit these pollutants. Accordingly, BACT analyses were conducted for the following TEC emission sources:

- Main boiler.
- Auxiliary boiler.
- Emergency firewater pump and generator diesel engines.

- Mechanical draft cooling tower.
- Solid fuel, limestone, and byproduct material storage and handling systems.

The main boiler, auxiliary boiler, and emergency diesel engines will emit pollutants associated with fuel combustion including NO_x, CO, SO₂, VOC, PM/PM₁₀, H₂SO₄ mist, and fluorides. BACT analyses were therefore conducted for each of these combustion-related PSD pollutants for the main boiler, auxiliary boiler, and emergency diesel engines. The mechanical draft cooling tower and material storage and handling systems will only emit PM/PM₁₀. The BACT analysis for these TEC emission sources was therefore confined to PM/PM₁₀.

The principal TEC emission source is the supercritical pulverized coal main boiler. Emissions from the main boiler comprise 99.5 percent of total estimated TEC project annual emissions. Accordingly, the primary emphasis of the BACT analysis conducted for TEC was directed to the main boiler. The main boiler will be equipped with a comprehensive state-of-the art emission control system that includes boiler combustion controls (i.e., low-NO_x burners and overfire air), SCR, fabric filter, wet FGD, and a WESP. This extensive system of emission control equipment will reduce emissions of the two primary pollutants (SO₂ and NO_x) to the lowest rates that have been proposed for any pulverized coal plant in the United States, and lower than the BACT limits in any permitted pulverized coal utility boiler.

Supercritical pulverized coal technology will be used by TEC to generate electricity. Supercritical boiler and steam turbine design can deliver greater gross thermal efficiency compared to subcritical power generating cycles. As a result, a supercritical design requires less fuel than a subcritical design to generate the same gross power output. The selection of the supercritical design condition must consider the benefit of incremental improvements in efficiency that come with higher main and reheat steam temperature and pressure compared to the cost, heavier loads on structural supports, startup characteristics, selection of fuels, and availability impacts that can result from the need for higher grade alloy materials, more difficult weld procedures, and thicker wall pipe and equipment components. The TEC operating conditions previously described in Section 2.3.1 were

selected as those that best meet the project's overall objectives. An evaluation of alternative electrical generating technologies is provided in Section 5.2 for informational purposes.

Although there is no generally accepted definition of ultra-supercritical (USC) steam conditions, USC is used to describe boiler/steam turbine systems that operate at incrementally higher steam turbine pressures and temperatures compared to supercritical (SC) units. While there is no *bright line* definition that separates USC from SC, supercritical pressures and main and reheat steam temperatures greater than about 600°C (1,112°F) are generally considered to represent USC conditions. Regardless of the term used to describe the operating steam conditions, higher steam pressures and temperatures will result in higher thermal efficiencies. The extent of thermal efficiency improvement depends on the magnitude of the increases in steam pressure and temperature.

Control technology analyses using the five-step top-down BACT method are provided for in Section 5.3 (for NO_x), Section 5.4 (for SO₂), Section 5.5 (for CO and VOC), Section 5.6 (for H₂SO₄ mist and fluorides), and Section 5.7 (for PM/PM₁₀). CO and VOC are addressed in one section since these pollutants have a common origin (i.e., both are products of incomplete fuel combustion) and similar available control technologies. The two acid gases (H₂SO₄ mist and fluorides) are also addressed in one section since these pollutants are controlled using similar control technologies.

5.1.1 BACT ANALYSIS FOR STARTUPS

TEC will be a base load unit with an estimated capacity factor of 90 percent. The frequency of unit startups will therefore be low. Each unit startup will also be preceded by an outage—during the outage period there will be no emissions from the main boiler. Startups of the TEC main boiler will be conducted using best operational practices to minimize emissions and duration consistent with process and safety considerations. The main boiler wet FGD and WESP control systems will be in service throughout the startup cycle. However, the SCR control system cannot be placed in service until the boiler flue gas temperature reaches the minimum SCR catalyst operating temperature. Similarly, the fabric filter internal bypass will be in use until solid fuel firing comprises at least

20 percent of the total ULSD fuel oil/coal heat input to prevent blinding of the filter bags. Excess emissions associated with startup events were previously discussed in Section 2.5.

5.1.2 BACT 24-HOUR BLOCK AVERAGE EMISSION LIMITS

As previously noted, the extensive system of emission control equipment proposed for the TEC main boiler will reduce emissions of the two primary pollutants (SO_2 and NO_x) to the lowest rates that have been proposed for any pulverized coal plant in the United States, and lower than the BACT limits in any permitted pulverized coal utility boiler. To better enable compliance with these stringent emissions limits, TEC requests that where 24-hour block averages are applicable, that this block be considered to begin and end at 6 a.m. rather than midnight. If necessary, this provision will permit TEC to adjust load downward during the nighttime hours, corresponding with the period when daily electrical demand is also reduced.

5.2 EVALUATION OF ALTERNATIVE ELECTRICAL GENERATION TECHNOLOGIES

As discussed in Section 5.1, the first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions for the pollutant under evaluation. Control technologies typically considered in a BACT analysis include process modifications that reduce the formation of pollutants and post-process emission control systems that reduce emissions after the pollutants are formed. An example of the former is the use of low- NO_x burners to alter the combustion process and reduce the formation of NO_x . The use of SCR to reduce NO_x following its formation in the combustion process is an example of a postprocess emission control system. These types of control technologies, when applicable, are appropriately considered in a BACT analysis.

Evaluation of process alternatives that would involve completely “redefining the design” of the proposed process are not required to be considered (reference the 1990 Draft New Source Review Workshop Manual, Section IV.A.3). Alternative electrical generating processes, such as natural gas-fired or integrated gasification combined-cycle plants, represent completely different power generation plant designs compared to the supercritical pulverized coal technology selected for TEC. While all electrical generation technologies generate elec-

tricity, the technical basis for the supercritical pulverized coal technology is substantially different from a natural gas-fired or integrated gasification combined-cycle (IGCC) plant. Since a natural gas-fired or IGCC electrical generating plant represents a completely different process compared to supercritical pulverized coal technology, a BACT analysis of these alternative electrical generation technologies is not required because these process alternatives would “redefine the design” of the TEC Project.

Although a BACT analysis of alternative electrical generation technologies is not required, the TEC Participating Utilities contracted with URS to conduct a study of available coal-based generation technologies prior to selecting the supercritical pulverized coal technology. This study evaluated commercially available coal-based technologies, including IGCC, with respect to technical attributes, fuel flexibility, commercial experience and size, efficiency, availability, environmental profile, and cost. Based on an evaluation of these factors, supercritical pulverized coal technology was determined the best electrical generation technology for the TEC Project. A complete copy of the URS report, Coal-Based Technology Evaluation for TEC, is included in the SCA as Appendix 10.9.

5.3 BACT ANALYSIS FOR NO_x

5.3.1 SUPERCRITICAL PC BOILER

NO_x emissions from combustion sources consist of two components: oxidation of atmospheric nitrogen contained in the combustion air (thermal NO_x and prompt NO_x) and conversion of chemically bound fuel nitrogen (fuel NO_x). Thermal NO_x results when atmospheric nitrogen is oxidized at the high temperatures occurring in the boiler firebox to yield NO, NO₂, and other oxides of nitrogen. Most thermal NO_x is formed in high temperature areas downstream of the burners where combustion air has mixed sufficiently with the fuel to produce a peak temperature. The rate of formation of thermal NO_x is a function of residence time and free oxygen and varies exponentially with peak flame temperature. Prompt NO_x forms within the combustion flame and is usually negligible when compared to the amount of thermal NO_x formed. Fuel-related NO_x is formed from oxidation of chemically bound nitrogen present in the coal. Most boiler NO_x emissions originate as nitric oxide (NO). NO generated by the combustion process is subsequently

further oxidized downstream of the combustion zone or in the atmosphere to the more stable NO₂ molecule.

5.3.1.1 Available NO_x Control Technologies

Available technologies for controlling NO_x emissions from pulverized coal boilers include combustion process modifications and postcombustion exhaust gas treatment systems. Available combustion process modifications include low-NO_x burners, overfire air (OFA), natural gas reburn (NGR), and flue gas recirculation (FGR). Available postcombustion controls include selective non-catalytic reduction (SNCR), EMx™ (formerly SCONOx™), and SCR. A description of each of these control technologies is provided in the following subsections.

Low-NO_x Burners

Low-NO_x burners reduce NO_x by completing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame and results in one or more of the following conditions: (a) reduced oxygen in the primary flame zone; (b) reduced flame temperature; and (c) reduced residence time at peak temperature. The lower oxygen levels, flame temperatures, and residence times will suppress the formation of thermal NO_x. NO_x emission reductions of 30 to 50 percent have been achieved with low-NO_x burners.

Low-NO_x burner technology has been widely applied to coal-fired boilers of all sizes and is typically applied to new boilers in conjunction with post-combustion NO_x emission control technologies. An unavoidable adverse consequence of staged combustion technologies, including low-NO_x burners, is an increase in the products of incomplete fuel combustion including CO, VOCs, and ash carbon content.

Overfire Air

OFA is another form of staged combustion. In the primary combustion zone, combustion air is diverted from the burners creating a fuel rich zone in the lower section of the boiler. This oxygen deficient zone decreases the conversion of fuel-bound nitrogen to NO_x. Ad-

ditional combustion air is injected above the primary combustion zone to complete the combustion process. The OFA is injected using a wind-box equipped with ports and/or nozzles. The resulting reduction in temperature decreases the production of thermal NO_x . OFA technology is typically used in conjunction with low- NO_x burners to provide the air required to complete the combustion process and limit the formation of CO and VOC. —

Natural Gas Reburn

NGR is a process that diverts some of the heat input from the main boiler combustion zone to an area above the main boiler burners. This diversion creates a secondary *reburn* combustion zone. Natural gas is injected in the reburn zone producing a slightly fuel rich section. OFA is then added above the reburn zone to complete the combustion process. As NO_x formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) due the combustion of natural gas in the reburn zone, it is converted to molecular nitrogen (N_2). NGR has been demonstrated to reduce NO_x emissions by approximately 40 to 70 percent on several existing coal-fired boilers.

Flue Gas Recirculation

FGR recirculates boiler flue gas from the boiler outlet to the furnace where is re-introduced into the combustion process. Fuel/air mixing in the combustion region is increased by the recirculated flue gas during the early stages of combustion. This increased mixing and reduction in peak flame temperatures results in lower thermal NO_x formation. The amount of NO_x reduction is dependant upon the burner and furnace design. FGR has been demonstrated as a NO_x reduction technology on natural gas- and oil-fired boilers. The application of FGR technology to coal fuel-fired boilers poses operational and maintenance concerns due to the recirculation of high temperature, high ash content exhaust gases.

Selective Non-Catalytic Reduction

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor. The two commercial applications of SNCR include the Electric Power Re-

search Institute's (EPRI's) NO_xOUT and Exxon's Thermal DeNO_x processes. The two processes are similar in that either ammonia (Thermal DeNO_x) or urea (NO_xOUT) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal DeNO_x process are as follows:



The NO_xOUT process is similar with the exception that urea is used in place of ammonia.

The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted ammonia to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor Reaction (1) resulting in a reduction in NO_x emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Since Equations (1) and (2) are theoretical, some of the injected ammonia will not react completely to form nitrogen and water. This unreacted ammonia will be emitted into the atmosphere as ammonia slip. Excess ammonia in the atmosphere may produce ammonium salts and further develop into PM_{2.5} or PM₁₀ particles. The amount of ammonia slip emitted will depend on three factors: (1) the extent of mixing of the injected ammonia and fuel combustion products; (2) temperature in the mixing zone; and (3) residence time. Therefore, ammonia slip formation is related to the physical characteristics of the boiler and achievable NO_x control efficiency.

In a typical coal-fired boiler, the combustion chamber is not designed to provide adequate mixing within a consistent temperature zone to achieve a satisfactory NO_x control efficiency using SNCR. For a pulverized coal boiler, SNCR typically achieves NO_x control efficiencies of 40 to 60 percent.

Selective Catalytic Reduction

In contrast to SNCR, SCR reduces NO_x emissions by reacting ammonia with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed where the following primary reactions take place:



The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NO_x molar ratio, catalyst reactivity, catalyst age, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with ammonia theoretically requires a 1:1 molar ratio. Ammonia/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive ammonia slip emissions.

As is the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for SCR operation is dependent on the type of catalyst used. The two main groups of catalyst are base metal (vanadium-platinum or -titanium) and zeolite. The optimum temperature range for a vanadium-platinum catalyst is less than 500°F while the optimum temperature range for a vanadium-titanium catalyst is to 550 to 800°F. The zeolite catalyst is used for higher temperature applications and can operate effectively at temperatures as high as 1,000°F. At temperatures below the optimum range

for the specified catalyst, reduction Reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NO_x emissions.

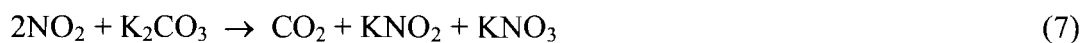
SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium. The catalyst life does not include this potential for degradation that could cause early replacement of the catalyst.

Ammonia slip becomes a greater issue as the catalyst degrades because of the increased amount of ammonia injected to achieve the appropriate NO_x control. Vendors typically can provide SCR systems that have the ability to limit the concentration of ammonia slip to 10 parts per million by dry volume (ppmvd) throughout the life of the catalyst.

EMx™ (SCONO_x™)

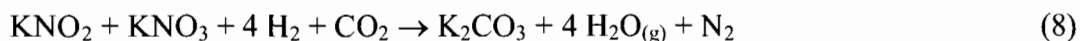
EMx™ (formerly referred to as SCONO_x™) is a multipollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology that is designed to simultaneously reduce NO_x, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ system employs a single catalyst to simultaneously oxidize CO to CO₂ and NO to NO₂. NO₂ formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The EMx™ oxidation/absorption cycle reactions are:



CO₂ produced by Ractions (5) and (7) is released to the atmosphere as part of the exhaust stream.

As shown in Raction (7), the potassium carbonate catalyst coating reacts with NO₂ to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO₂ in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The EMx™ regeneration cycle reaction is:



Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

The EMx™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in an appropriate temperature section of the exhaust stream. For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. The reformer catalyst works to partially reform the methane gas to hydrogen (2 percent by volume) to be used in the regeneration of the EMx™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction as shown by the following equation:



The reformer catalyst is placed upstream of the EMx™ catalyst in a steam reformer reactor. The reformer catalyst is designed for a minimum 50-percent conversion of methane to hydrogen.

The EMx™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. The EMx™ system is typically used to control emissions from natural gas-fired combustion turbines in which the sulfur concentration in the exhaust stream is low. The higher concentrations of sulfur resulting from the combustion of coal will poison the EMx™ catalyst at a rapid rate. Accordingly, EMx™ technology is not feasible for coal-fired boilers.

5.3.1.2 Technical Feasibility and Ranking

The staged combustion process modifications described previously are technically feasible with the exception of FGR and NGR. FGR is not considered feasible for coal fuel-fired boilers due to the operational and maintenance issues associated with recirculating high temperature, high ash content exhaust gases. TEC will not use natural gas as a fuel source, and the Site will not have access to natural gas pipelines. Of the available post-combustion control technologies, both SNCR and SCR are feasible. The EMx™ technology has not been demonstrated on coal fuel-fired boilers and is not technically feasible due to sulfur present in the exhaust gases from coal-fired boilers.

Table 5-1 provides a summary of the technical feasibility and ranking of the available NO_x control technologies. As shown, SCR in combination with low-NO_x burners/OFA staged combustion offers the highest control efficiency.

5.3.1.3 Evaluation of Control Technologies

TEC proposes to install the NO_x control technologies identified as having the highest control efficiency—low-NO_x burners/OFA and SCR. The economic and energy impacts associated with the installation and operation of this combination of control technologies are considered reasonable. There are also no significant collateral environmental issues that would justify rejection of these control technologies as BACT.

Table 5-1. Ranking of Available NO_x Control Technologies—Main Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency Range (%)
SCR and low-NO _x burners/OFA	Yes	80 to 90
SNCR	Yes	40 to 60
Low-NO _x burners/OFA	Yes	30 to 50
EMx™	No	Not applicable
FGR	No	Not applicable
Natural gas reburn	No	Not applicable

Source: ECT, 2007.

5.3.1.4 Proposed NO_x BACT

Table 5-2 provides a summary of recent coal-fired utility boiler NO_x BACT determinations. BACT determinations with the lowest emission rates are based on use of low-NO_x burners/OFA and SCR technology achieving 0.06 lb/MMBtu. TEC proposes a NO_x emission rate of 0.05 lb/MMBtu on both a 30-day rolling and 24-hour block average basis. The proposed TEC main boiler NO_x BACT emission limit is lower than any permitted coal-fired power plant in the United States and lower than the draft permit limit of 0.06 lb/MMBtu (24-hour block) average recently issued by EPA Region 9 for the proposed New Mexico 1,500-MW coal-fired Desert Rock Energy Facility. NO_x BACT proposed for the TEC main boiler is summarized as follows:

- Emission Limit—0.05 lb/MMBtu (373.8 lb/hr).
- Averaging Periods—30-day rolling (24-hour block).
- Compliance Method—Continuous emissions monitoring in accordance with 40 CFR 75.

Table 5-3 provides a summary of preliminary SCR design parameters.

5.3.2 AUXILIARY BOILER

TEC will be equipped with a 375-MMBtu (HHV) auxiliary boiler fired with ULSD. Total annual fuel use in the auxiliary boiler will be limited to 328,500 million British thermal units per year (MMBtu/yr). This annual fuel heat input is equivalent to an auxiliary boiler capacity factor of 10 percent (i.e., operating no more than 876 hr/yr at full load).

The NO_x control technologies previously described for the pulverized coal main boiler are also applicable to the auxiliary boiler.

5.3.2.1 Technical Feasibility

All of the staged combustion technologies previously described in Section 5.3.1 for the pulverized coal main boiler are feasible for the auxiliary boiler with the exception of NGR. As previously noted, TEC will not use natural gas as a fuel source and the Site will

Table 5-2. Summary of Coal-Fired Power Plant NQ BACT Determinations (Page 1 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limit NO _x (lb/MMBtu)
Springerville Generating Station (Tucson Electric Power Co)	AZ	Apr 2002	3, 4	PC	800	LNB/SCR	0.170
Plum Point Energy Station (Plum Point Energy Associates, LLC)	AR	8/20/03	1	PC	800	SCR	0.090
Comanche Plant Unit 3 (Public Service Company of CO)	CO	Jul 2005	3	PC	750	SCR	0.080
Xcel Energy	CO	Jul 2005		PC	750	SCR; not subject to PSD review 30-day average	0.080
Indiantown Cogeneration Plant (Indiantown Cogeneration, LP)	FL	1995	1	PC	330	SCR	0.170
Seminole Electric Unit 3	FL	Draft	3	SCPC	750	SCR; not subject to PSD review	
Stanton Energy Center (MUA/OUC/FMPA)	FL	1996	2	PC	468	SCR	0.170
Longleaf Energy Station (LS Power)	GA	Draft	1, 2	PC	600	SCR	0.070
Holcomb Generating Station (Sand Sage Power, LLC)	KS	4/5/04	2	PC	660	LNB/OFA/SCR	0.070
Louisville Gas & Electric	KY	Jan 2006		SCPC	750	SCR; not subject to PSD review	0.110
Thoroughbred Generating Station (Thoroughbred Generating Co, LLC)	KY	May 2006	1,2	PC	1,500	SCR	0.070
MidAmerican Energy Center Council Bluffs (MidAmerican Energy)	IA	6/17/03	4	SCPC	750	SCR	0.070
Baldwin Expansion (Dynergy)	IL	Pending	1,2	PC	750		0.080
Dellman Unit 4 (City Water Light & Power - Springfield, IL.) (Not subject to SO ₂ or NO _x BACT)	IL	Draft (Feb 2006)	4	PC	250	Not subject to PSD review	0.100
Prairie State (Prairie State Generating Co, LLC)	IL	Apr 2005	1,2	PC	1,500	SCR	0.070
Prairie Energy Power Plant (Corn Belt Energy Corporation)	IL	12/17/02	1	PC	91	SCR 30-day rolling average	0.120
Franklin Energy Coal Project (Illinois Energy Group)	IL	Pending	1,2	PC	680		0.080
NRG Energy (Big Cajun II) (Louisiana Generating, LLC)	LA	Aug 2005	2	SCPC	575	LNB/SCR 30-day rolling average	0.070
KCP&L Latan Generating	MO	Jan 2006	1	PC	850	SCR 30-day average	0.080
Weston Bend Generating Station (Great Plains Power Company)	MO	Nov 2001	1	PC	820	30-day average	0.080
Southwest Power Station (City Utilities of Springfield)	MO	12/15/04	2	PC	275	SCR	0.080
Roundup Power Project (Bull Mountain Development Co)	MT	7/21/03	1, 2	PC	780	SCR	0.070 0.100
Rocky Mountain Power (Rocky Mountain Power, Inc.)	MT	6/11/02	1	PC	113	30-day average	0.090
Montana Dakota Utilities	ND	Jun 2005		PC	220		0.09

Table 5-2. Summary of Coal-Fired Power Plant NO_x BACT Determinations (Page 2 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limit NO _x (lb/MMBtu)
Whelan Energy Center (Hastings Utilities)	NE	Mar 2004	1	PC	220	SCR 30-day average	0.08
Nebraska City Unit 2 (Omaha Public Power District)	NE	Mar 2005	2		660	SCR 30-day average	0.07
Newmont TS Power Plant (Newmont NV Energy Investment, LLC)	NV	May 2005		PC	200	LNB/SCR	0.067
Desert Rock Energy Facility (Steag Power, LLC)	NM	Pending	1, 2	PC	750	SCR 24-hour average	0.06
Cottonwood Energy Center (Chaco Valley Energy, LLC)	NM	Pending	1	PC	495		0.06
Mustang Generating Station (Chaco Valley Energy, LLC)	NM	Pending	1	PC	330		0.06
Santee Cooper Cross (Not subject to SO ₂ or NO _x BACT)	SC	2/5/04	3,4	PC	660	SCR	0.08
Calaveras Plant Spruce Unit 2 (Not subject to SO ₂ or NO _x BACT)	TX	12/05	2	PC	750		0.069
City Public Service	TX	Sep 2005		PC	750	SCR	0.069
Sandy Creek Energy (LS Power)	TX	Pending	1	PC	500	30-day average	0.07
Intermountain Power (Intermountain Power Service Corp)	UT	10/15/04	3	PC	950	SCR	0.07
Weston Unit 4 (Wisconsin Public Service Company)	WI	Oct 2004	1	PC	500		0.07
Elm Road Generating Station (We Energy - formerly WEPSCO)	WI	1/14/04	1,2	SCPC	1,230	SCR	0.07
Public Service Corp Wausau	WI	Oct 2004		SCPC	500	LNB/SCR	0.06
Longview Power (Longview Power, LLC)	WV	3/2/04	1	PC	600	SCR	0.08
WYGEN II (Black Hills Corporation)	WY	Sep 2002	1	PC	500	30-day average	0.07
Black Hills (Black Hills Corporation)	WY	Jun 1999	1	PC	80	30-day average	0.22
Two Elk (Two Elk Generation Partners, L.P.)	WY	May 2003	1	PC	250		0.09
Minimum							0.060
Maximum							0.220
Average							0.088
Median							0.080

Source: ECT, 2007.

Table 5-3. Anticipated SCR Operating Parameters

Parameter	Unit	Estimated Design Value	Notes
Catalytic reaction temperature	°F	675 to 725	
Inlet gas temperature	°F	700 to 715	
Inlet gas flow rate	lb/hr	8,900,085 design maximum	Inlet gas flow rate depends on fuel blend; design flow rate listed to the left is for the 100-percent Latin American coal case
Reducing agent		Anhydrous ammonia	
Maximum ammonia feed rate	lb/hr	891 design maximum 869 design average	Ammonia feed rates were calculated assuming a NO _x emission rate from the boiler of 0.35 lb/MMBtu and a controlled NO _x emission rate of 0.05 lb/MMBtu
NO _x inlet concentration	ppmvd at 3-percent oxygen	180 to 250 (0.25 to 0.35 lb/MMBtu)	
NO _x outlet concentration	ppmvd at 3-percent oxygen	35 (0.05 lb/MMBtu)	
NO _x control efficiency	%	80 to 85	
Ammonia slip	ppmvd	5 ppm design maximum	
Catalyst life	year	2 to 3	

Source: S&L, 2007.

not have access to natural gas pipelines. Of the available postcombustion NO_x control technologies, only SCR is considered technically feasible. Both SNCR and the EMx™ technologies have constraints on exhaust gas temperatures that would prevent these technologies from being applied to the auxiliary boiler.

5.3.2.2 Proposed NO_x BACT

The auxiliary boiler will operate with a capacity factor of no more than 10 percent, which is equivalent to 876 hr/yr operation at design capacity. Installation of FGR or SCR would result in excessive costs on a dollar per ton of NO_x removed basis due to the limited annual operating hours of the auxiliary boiler.

Use of low-NO_x burner control technology achieving 0.09 lb/MMBtu, together with a constraint on annual operations, is proposed as NO_x BACT for the auxiliary boiler. The proposed emission limit is lower than the auxiliary boiler NO_x BACT limit of 0.10 lb/MMBtu recently proposed by the Georgia Environmental Protection Division (GEPD) for the Longleaf Energy Facility and by EPA Region 9 for the New Mexico Desert Rock Energy Facility. NO_x BACT proposed for the TEC auxiliary boiler is summarized as follows:

- Emission Limit—0.09 lb/MMBtu.
- Averaging Period—Duration of stack test.
- Compliance Method—Stack test using EPA Reference Methods.
- Annual Heat Input—328,500 MMBtu/yr.
- Averaging Period—Calendar year.
- Compliance Method—Fuel consumption monitoring.

5.3.3 EMERGENCY DIESEL ENGINES

TEC will include a diesel engine-driven emergency generator rated at 1,640 kW, and a diesel engine-driven firewater pump rated at 432 hp. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. Total estimated NO_x emissions for both diesel engines is approximately 1 tpy.

The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for new nonroad CI engines. Subpart IIII limits the combination of NO_x and nonmethane hydrocarbons (NMHC) emissions to 6.4 grams per kilowatt-hour (g/kW-hr) for emergency generators purchased in 2007 or later. For firewater pumps, Subpart IIII also limits the combination of NO_x and NMHC emissions, but the emission limits (Tier II or III) are dependent upon the model year in which the pump was manufactured. Emergency diesel engines purchased for TEC will comply with the applicable emission standards of NSPS Subpart IIII.

Compliance with the stringent NSPS Subpart IIII emission standards and limited annual operating hours is proposed as NO_x BACT for the TEC emergency generator and firewater pump diesel engines. NO_x BACT proposed for the TEC emergency diesel engines is summarized as follows:

- Emission Limit—Applicable standards of NSPS Subpart IIII.
- Averaging Period—Per NSPS Subpart IIII.
- Compliance Method—Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.4 BACT ANALYSIS FOR SO₂

5.4.1 SUPERCRITICAL PC BOILER

Emissions of sulfur oxides from pulverized coal boilers result from the oxidation of sulfur present in the fuel. Sulfur oxides formed during coal combustion are primarily SO₂, with minor amounts of sulfur trioxide (SO₃) and gaseous sulfates. These sulfur compounds form as the organic and pyretic sulfur in the coal are oxidized during the combustion process. Approximately 95 percent of the sulfur present in bituminous coal will be oxidized to SO₂, with 0.7 percent of fuel sulfur oxidized to SO₃ and gaseous sulfate. Un-

controlled sulfur oxide emissions from coal-fired boilers vary directly with the sulfur content of the coal and are unaffected by the boiler combustion process or size.

5.4.1.1 Available SO₂ Control Technologies

Available control technologies for reducing SO₂ emissions from pulverized coal boilers include use of lower sulfur coals and postcombustion dry and wet FGD.

Low Sulfur Coal

Since uncontrolled SO₂ emissions from pulverized coal boilers are directly proportional to the sulfur content of the coal combusted, use of lower sulfur coals will reduce the uncontrolled SO₂ emission rate.

Fuel flexibility to be able to take full advantage of competitive fuel pricing and availability opportunities and transportation options in the future marketplace to provide low cost, reliable electricity to their customers is an important TEC design criterion. The unit will be designed to fire 100-percent bituminous coal, blends of bituminous and subbituminous coals, and blends of bituminous or subbituminous coal with petcoke. The maximum amount of petcoke blended with coal will be up to 30 percent by weight. Bituminous coal for the proposed facility will typically be from either Latin America or Central Appalachia. Subbituminous coal will typically be from the PRB area of northeast Wyoming.

The TEC fuel selection investigation determined that blends of petcoke with Latin American, PRB, and Central Appalachian coals are the most cost-competitive fuels among the range of coals and coal blends evaluated. In each case, the maximum proportion of petcoke blended with a lower sulfur coal will be restricted to limit uncontrolled SO₂ emissions to a maximum of 3.46 lb/MMBtu. The maximum uncontrolled SO₂ emission rate of 3.46 lb/MMBtu is based on the expected maximum day-to-day SO₂ removal capability of the latest generation of wet limestone FGD systems and the BACT SO₂ emission limits proposed for the TEC main boiler.

The chemistry of wet scrubbing consists of a complex series of kinetic and equilibrium-controlled reactions occurring in the gas, liquid, and solid phases. The amount of SO₂ removed from the flue gas is governed by the vapor-liquid equilibrium between SO₂ in the flue gas and the absorbent liquor. As the flue gas SO₂ concentration decreases, absorption will be limited by the SO₂ equilibrium vapor pressure. Wet FGD control systems can be designed to achieve controlled SO₂ flue gas concentrations as low as approximately 20 ppmvd at 3-percent oxygen (i.e., controlled SO₂ flue gas concentrations below approximately 20 ppmvd at 3-percent oxygen using wet FGD technology are not achievable even when firing lower sulfur fuel blends).

Accordingly, the fuels planned for TEC include lower sulfur coals that are consistent with the need for fuel flexibility and use of state-of-the-art wet FGD control technology achieving the lowest SO₂ emission rate of any proposed or permitted pulverized coal utility boiler. The TEC main boiler wet FGD control system will reduce uncontrolled SO₂ emissions by 98.8 percent and achieve a controlled SO₂ exhaust concentration of approximately 20 ppmvd at 3-percent oxygen. Further limiting the sulfur content of the fuel would not result in reduced controlled SO₂ emissions.

Wet FGD

Wet FGD systems remove SO₂ from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. Pulverized coal utility boiler wet FGD systems typically involve the reaction of limestone and exhaust gas sulfur oxides in a spray absorber tower. Boiler exhaust gas enters at the bottom of the absorber tower, flows vertically through the limestone/water spray, passes through a mist eliminator to remove reentrained limestone slurry droplets, and then exits the tower. Ground limestone in the scrubbing slurry reacts with SO₂ in the flue gas to form calcium sulfite and calcium sulfate (i.e., gypsum). The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced (i.e., by blowing compressed air into the slurry in the retention tank in the base of the tower or in an external oxidation tank) depending on the desired byproduct.

Wet FGD systems will generate wastewater and wet sludge streams requiring treatment and disposal. Gypsum slurry from the reaction tank is typically treated in a series of hydroclones. Reclaimed water from the hydroclones is returned to the scrubber system and gypsum solids sent to a vacuum filtration system. Gypsum solids from the vacuum filter system may be washed to remove contaminants and then loaded into railcars or trucks for shipment as a byproduct or mixed with fly ash, if necessary, and conveyed to a landfill.

The most common pulverized coal utility boiler wet FGD application uses limestone as the reagent and forced oxidation of the reaction byproducts to form calcium sulfate since calcium sulfate is easier to dewater than calcium sulfite. Current generation utility boiler wet FGD systems are typically designed with one scrubber module sized and designed to treat 100 percent of the maximum flue gas flow rate.

Other wet FGD technologies include the use of lime, magnesium enhanced lime (MEL), and dual-alkali reagents and alternative scrubbing equipment such as the Chiyoda Jet Bubbling Reactor (JBR). These wet FGD technologies achieve comparable or lower SO_2 removal efficiencies compared to the previously described limestone-forced oxidation (LSFO) wet FGD technology. Each of these wet FGD technologies is briefly described in the following paragraphs.

Lime Wet FGD

Lime wet FGD technology is similar to that described previously for limestone with hydrated lime ($\text{Ca}[\text{OH}]_2$) used as the alkaline reagent instead of limestone (CaCO_3). The primary advantage of limestone versus lime as the wet FGD reagent is the significantly lower cost of limestone.

MEL Wet FGD

In the MEL process, slaked lime containing calcium hydroxide ($\text{Ca}[\text{OH}]_2$) and magnesium hydroxide ($\text{Mg}[\text{OH}]_2$) is used to react with SO_2 . The slurry is added to a recycle tank at the bottom of the absorber under pH control to replenish the reagent consumed. Calcium hydroxide in the slurry reacts with most of the SO_2 to precipitate calcium sulfite

($\text{CaSO}_3 \times \frac{1}{2} \text{H}_2\text{O}$). Magnesium hydroxide reacts with the remainder of the SO_2 to form soluble magnesium salts, magnesium sulfite, and magnesium bisulfite. These soluble magnesium salts increase SO_2 capture and allow reduction in power consumption and equipment costs. Magnesium sulfite is replenished by addition of fresh lime slurry to the reaction tank.

MEL scrubber systems can achieve 98-percent SO_2 removal efficiency using absorber towers significantly smaller than limestone reagent systems. The presence of magnesium effectively increases the dissolved alkalinity and makes removal less dependent on lime dissolution. For the same removal efficiency, limestone based systems require a higher liquid-to-gas ratio. The selection of LSFO or MEL wet FGD technology is generally based on site-specific considerations involving the higher operating cost of lime and the higher capital cost of the larger absorbers and greater pumping costs of LSFO.

Dual-Alkali Wet FGD

Dual-alkali systems employ sodium- and calcium-based reagents to remove SO_2 from the flue gas and regenerate the scrubbing reagent. Due to the relatively high cost of sodium-based reagents and improvements in LSFO wet FGD technology, dual-alkali wet FGD technology is considered an inferior technology to LSFO wet FGD.

Chiyoda JBR

The Chiyoda wet FGD technology uses a unique JBR to react limestone reagent and flue gas. The flue gas is first quenched in a gas cooler prior to entry into the JBR. In the JBR, the flue gas is forced through numerous sparger pipes submerged below the absorbent liquid level. The flow of flue gas through the alkaline absorbent liquid results in mass transfer of SO_2 from the gas phase to the liquid phase. Absorbent liquid and oxidation air is also introduced into the JBR enhancing the mixing of limestone slurry and flue gas. The treated flue gas proceeds to the upper part of the JBR, passes through a mist eliminator, and then enters the stack. The oxidized gypsum is removed from the JBR for dewatering. The Chiyoda process combines all FGD reactions in the JBR. The overall chemical reactions are identical to those of LSFO wet FGD technology.

In addition to controlling SO₂ emissions, wet FGD systems also have the cobenefit of removing PM, H₂SO₄ mist, hydrogen chloride, HF, and mercury.

Dry Flue Gas Desulfurization

Dry FGD control systems include spray tower absorber (SDA), circulating dry scrubber (CDS), and duct sorbent injection (DSI) control technologies.

In a SDA control system, the combustion process exhaust stream passes through the SDA upstream of a PM control device (typically a fabric filter). An alkaline lime slurry is injected in the SDA using a rotary atomizer or fluid nozzles. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO₂ are dried by heat contained in the exhaust stream. If a fabric filter is used as the PM control device, the alkaline lime reagent may further react with SO₂ that passes through the filter cake. This additional reaction in the fabric filter can also aid in the removal of additional pollutants (i.e., H₂SO₄ mist, HCl, HF, and mercury).

CDS technology uses flue gas, coal ash, and lime sorbent to form a fluidized bed in an absorber vessel. Water is added to the CDS absorber vessel to enhance the lime and SO₂ absorption reactions. Byproducts leave the absorber in a dry form with the flue gas for subsequent removal by a downstream PM collection device.

Duct sorbent injection (DSI) is another once-through dry FGD technology that uses dry lime or limestone as the reagent to absorb SO₂. DSI control technology injects the alkaline reagent in the ductwork between the air heater and the particulate collection device. The sulfite/sulfate salts reaction products are then removed by the particulate collection device.

Due to the lower SO₂ control efficiencies of dry FGD technologies compared to wet FGD, dry FGD technologies are typically installed on pulverized coal boilers that combust lower sulfur coals.

5.4.1.2 Technical Feasibility and Ranking

All of the available SO₂ control technologies described previously are technically feasible for the supercritical pulverized coal main boiler. With regards to the use of low sulfur coal, as previously noted the fuels planned for TEC include lower sulfur coals that are consistent with the need for fuel flexibility and use of state-of-the-art wet FGD control technology achieving the lowest SO₂ emission rate of any proposed or permitted pulverized coal utility boiler.

Table 5-4 provides a summary of the technical feasibility and ranking of the available SO₂ control technologies. As shown, wet FGD technology provides the highest control efficiency.

5.4.1.3 Evaluation of Control Technologies

TEC proposes to install the SO₂ control technology identified as having the highest control efficiency—wet FGD. The economic and energy impacts associated with the installation and operation of this control technology are considered reasonable. There are also no significant collateral environmental issues that would justify rejection of this control technology as BACT.

5.4.1.4 Proposed SO₂ BACT

Table 5-5 provides a summary of recent SO₂ BACT determinations for coal-fired utility boilers. BACT determinations with the lowest emission rates are based on both wet and dry FGD technology achieving 0.06 lb/MMBtu. TEC proposes SO₂ BACT emission rates of 0.04 lb/MMBtu on a 30-day rolling average basis, and 411.1 lb/hr basis on a 24-hour block average. The proposed 24-hour average SO₂ emission limit of 411.1 lb/hr is equivalent to 0.055 lb/MMBtu on a heat input basis. A higher short-term SO₂ emission limit on a pounds-per-hour basis is required due to the unavoidable normal fluctuations in wet FGD performance over a 24-hour period. The proposed TEC main boiler SO₂ BACT emission limits are lower than any permitted coal-fired power plant in the United States and lower than the draft permit limit of 0.06 lb/MMBtu (24-hour block) average recently

Table 5-4. Ranking of Available SO₂ Control Technologies—Main Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency Range* (%)
Wet FGD	Yes	90 to 98
Dry FGD—SDA and CDS	Yes	70 to 93
Dry FGD—DSI	Yes	50 to 80

*Control efficiencies vary depending on the level of uncontrolled SO₂ emissions.

Source: ECT, 2007.

Table 5-5. Summary of Coal-Fired Power Plant SO₂ BACT Determinations (Page 1 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limits SO ₂ (lb/MMBtu)
Springerville Generating Station (Tucson Electric Power Co)	AZ	Apr 2002	3, 4	PC	800	DFGD - SDA	0.600
Plum Point Energy Station (Plum Point Energy Associates, LLC)	AR	8/20/03	1	PC	800	DFGD	0.160
Comanche Plant Unit 3 (Public Service Company of CO)	CO	Jul 2005	3	PC	750	DFGD	0.100
Xcel Energy	CO	Jul 2005		PC	750	DFGD; not subject to PSD review 30-day average	0.100
Indiantown Cogeneration Plant (Indiantown Cogeneration, LP)	FL	1995	1	PC	330	DFGD	0.170
Seminole Electric Unit 3	FL	Draft	3	SCPC	750	WFGD; not subject to PSD review	
Stanton Energy Center (MUA/OUC/FMPA)	FL	1996	2	PC	468	WFGD	0.250
Longleaf Energy Station (LS Power)	GA	Draft	1, 2	PC	600	DFGD 24-hr average	0.120
Holcomb Generating Station (Sand Sage Power, LLC)	KS	4/5/04	2	PC	660	DFGD	0.095
Louisville Gas & Electric	KY	Jan 2006		SCPC	750	WFGD; not subject to PSD review	0.216
Thoroughbred Generating Station (Thoroughbred Generating Co, LLC)	KY	May 2006	1,2	PC	1,500	WFGD	0.410
MidAmerican Energy Center Council Bluffs (MidAmerican Energy)	IA	6/17/03	4	SCPC	750	DFGD	0.100
Baldwin Expansion (Dynergy)	IL	Pending	1,2	PC	750		0.250
Dellman Unit 4 (City Water Light & Power - Springfield, IL) (Not subject to SO ₂ or NO _x BACT)	IL	Draft (Feb 2006)	4	PC	250	Not subject to PSD review	0.200
Prairie State (Prairie State Generating Co, LLC)	IL	Apr 2005	1,2	PC	1,500	WFGD	0.181
Prairie Energy Power Plant (Corn Belt Energy Corporation)	IL	12/17/02	1	PC	91	FGD 30-day rolling average	0.150
Franklin Energy Coal Project (Illinois Energy Group)	IL	Pending	1,2	PC	680		0.080
NRG Energy (Big Cajun II) (Louisiana Generating, LLC)	LA	Aug 2005	2	SCPC	575	WFGD 30-day rolling average	0.100
KCP&L Latan Generating	MO	Jan 2006		PC	850	WFGD	0.100
Weston Bend Generating Station (Great Plains Power Company)	MO	Nov 2001	1	PC	820	DFGD	0.120
Southwest Power Station (City Utilities of Springfield)	MO	12/15/04	2	PC	275	DFGD - SDA	0.095
Roundup Power Project (Bull Mountain Development Co)	MT	7/21/03	1, 2	PC	780	DFGD 24-hour average	0.120
Rocky Mountain Power (Rocky Mountain Power, Inc.)	MT	6/11/02	1	PC	113	DFGD 30-day average	0.110
Montana Dakota Utilities	ND	Jun 2005		PC	220		0.360

Table 5-5. Summary of Coal-Fired Power Plant SO₂ BACT Determinations (Page 2 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limits SO ₂ (lb/MMBtu)
Whelan Energy Center (Hastings Utilities)	NE	Mar 2004	1	PC	220	DFGD-SDA	0.120
Nebraska City Unit 2 (Omaha Public Power District)	NE	Mar 2005	2		660	DFGD-SDA 30-day average	0.095
Newmont TS Power Plant (Newmont NV Energy Investment, LLC)	NV	May 2005		PC	200	DFGD	0.090
Desert Rock Energy Facility (Steag Power, LLC)	NM	Pending	1, 2	PC	750	WFGD	0.060
Cottonwood Energy Center (Chaco Valley Energy, LLC)	NM	Pending	1	PC	495		0.060
Mustang Generating Station (Chaco Valley Energy, LLC)	NM	Pending	1	PC	330		0.072
Santee Cooper Cross (Not subject to SO ₂ or NO _x BACT)	SC	2/5/04	3,4	PC	660	WFGD; not subject top BACT review	0.100
Calaveras Plant Spruce Unit 2 (Not subject to SO ₂ or NO _x BACT)	TX	12/05	2	PC	750		0.100
City Public Service	TX	Sep 2005		PC	750	WFGD	0.100
Sandy Creek Energy (LS Power)	TX	Pending	1	PC	500	DFGD	0.120
Intermountain Power (Intermountain Power Service Corp)	UT	10/15/04	3	PC	950	DFGD	0.100
Weston Unit 4 (Wisconsin Public Service Company)	WI	Oct 2004	1	PC	500		0.100
Elm Road Generating Station (We Energy - formerly WEPCO)	WI	1/14/04	1,2	SCPC	1,230	WFGD	0.150
Public Service Corp Wausau	WI	Oct 2004		SCPC	500	DFGD	0.060
Longview Power (Longview Power, LLC)	WV	3/2/04	1	PC	600	WFGD	0.150
WYGEN II (Black Hills Corporation)	WY	Sep 2002	1	PC	500	DFGD 30-day average	0.100
Black Hills (Black Hills Corporation)	WY	Jun 1999	1	PC	80	DFGD 30-day average	0.170
Two Elk (Two Elk Generation Partners, L.P.)	WY	May 2003	1	PC	250		0.132
Minimum							0.060
Maximum							0.600
Average							0.148
Median							0.110

Source: ECT, 2007.

issued by EPA Region 9 for the proposed New Mexico 1,500-MW coal-fired Desert Rock Energy Facility. Because the Desert Rock facility will be a mine-mouth plant, variability in the fuel characteristics will be limited. Based on information provided in its permit application, coal fired in the unit will generate approximately 1.84 lb/MMBtu potential SO₂ emissions. Therefore, the Desert Rock wet FGD control system will have to achieve a control efficiency of approximately 96.7 percent to meet the proposed BACT permit limit, which is significantly less than the 98.8-percent control efficiency TEC will need to achieve when firing fuel blends with up to 3.46 lb/MMBtu uncontrolled SO₂. SO₂ BACT emission limits proposed for the TEC main boiler are summarized as follows:

- Emission Limits—0.04 lb/MMBtu (411.1 lb/hr).
- Averaging Periods—30-day rolling (24-hour block).
- Compliance Method—Continuous emissions monitoring in accordance with 40 CFR 75.

Table 5-6 provides a summary of preliminary wet FGD design parameters.

5.4.2 AUXILIARY BOILER

The TEC 375-MMBtu (HHV) auxiliary boiler will be fired with ULSD fuel oil containing no more than 0.0015 percent sulfur by weight. The auxiliary boiler will also operate with a capacity factor of no more than 10 percent, which is equivalent to 876 hr/yr operation at design capacity. The use of very low-sulfur fuel oil and limited annual operating hours will result in auxiliary boiler SO₂ emissions of only 0.3 tpy.

In the auxiliary boiler, SO₂ is formed during the combustion process as a result of thermal oxidation of sulfur contained in the fuel oil. The only technically and economically feasible technology available to control SO₂ from auxiliary boilers is the use of low-sulfur fuel. Fuel treatment technologies are applied to fuel oils to reduce their sulfur contents prior to delivery to end fuel users.

Table 5-6. Wet FGD Parameters

Parameter	Unit	Estimated Design Value	Notes
General description		Wet FGD	
Number of scrubber modules		One, 100-percent	
Flue gas flow rate	acfm	2,937,838 design maximum	Flue gas flow to the fabric filter depends on the fuel blend; design flow rate listed to the left is for the 100-percent Latin American coal case
Flue gas temperature (inlet)	°F	275 to 300	
Pressure drop through scrubber	inches of water	8 (typical)	
Inlet SO ₂ concentration	lb/MMBtu	3.46 maximum	All coal/petcoke blends
Outlet SO ₂ concentration	lb/MMBtu	0.04	30 day rolling average
SO ₂ collection efficiency	percent	98.8	Maximum continuous operating efficiency
Calcium to sulfur molar ratio		1.03	
Sorbent feed rate	lb/hr	42,217 maximum	Design maximum based on PRB/petcoke fuel blend with 3.46 lb/MMBtu uncontrolled SO ₂
Sorbent analysis		CaCO ₃ 95.5% MgCO ₃ 3% CaO 0% Ash 1% Moisture 0.5%	Typical limestone sorbent analysis
Scrubber sludge generation rate	lb/hr	71,223 design maximum	Design maximum based on PRB/petcoke fuel blend with 3.46 lb/MMBtu uncontrolled SO ₂

Note: CaCO₃ = calcium carbonate.
MgCO₃ = magnesium carbonate.
CaO = calcium oxide.

Source: S&L, 2007

The exclusive use of ULSD fuel oil and constraints on annual operations are proposed as SO₂ BACT for the auxiliary boiler. SO₂ BACT proposed for the TEC auxiliary boiler is summarized as follows:

- Emission Limit—Exclusive use of ULSD fuel oil.
- Compliance Method—Supplier certifications of fuel oil sulfur content.
- Annual Heat Input—328,500 MMBtu/yr.
- Averaging Period—Calendar year.
- Compliance Method—Fuel consumption monitoring.

5.4.3 EMERGENCY DIESEL ENGINES

The TEC emergency generator and firewater pump diesel engines will each be fired with ULSD fuel oil containing no more than 0.0015 percent sulfur by weight. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. Estimated SO₂ emissions for both diesel engines are less than 0.01 tpy.

The diesel engines will emit SO₂ due to thermal oxidation of sulfur contained in the fuel oil. The only technically and economically feasible technology available to control SO₂ from emergency diesel engines is the use of low-sulfur fuel oil.

The exclusive use of ULSD fuel oil and constraints on annual operations are proposed as SO₂ BACT for the emergency diesel engines. SO₂ BACT proposed for the TEC emergency diesel engines is summarized as follows:

- Emission Limit—Exclusive use of ULSD fuel oil.
- Compliance Method—Supplier certifications of fuel oil sulfur content.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.5 BACT ANALYSIS FOR CO AND VOC

5.5.1 SUPERCRITICAL PC BOILER

Fuel combustion CO and VOC emissions result from the incomplete combustion of carbon and organic compounds contained in the fuel. Factors affecting CO and VOC emissions include firing temperatures, excess oxygen and residence time in the combustion zone, and combustion area mixing characteristics. An increase in combustion zone residence time and oxygen levels and improved mixing of fuel and combustion air will increase oxidation rates and decrease CO and VOC emission rates. Modern pulverized coal-fired boilers are designed and operated to minimize the formation of CO and VOC since these pollutants are indicative of inefficient combustion and unused energy.

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

5.5.1.1 Available CO and VOC Control Technologies

Three control technologies are available for reducing CO and VOC emissions from combustion sources: combustion controls, thermal oxidation, and catalytic oxidation.

Combustion Controls

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

Thermal Oxidation

A thermal oxidizer employs high temperature (approximately 1,500°F) combustion to achieve a 90- to 95-percent oxidization rate of CO and VOC to CO₂ and water. The thermal oxidizer components are subject to fouling by PM. Accordingly, for coal-fired boilers, the thermal oxidizer would need to be located downstream of the boiler's PM control device. In addition, a thermal oxidizer requires a source of supplemental fuel, typically natural gas, to raise the exhaust stream to the required oxidation temperature. There are no known installations of thermal oxidation technology to control CO and VOC emissions from coal-fired boilers.

Catalytic Oxidation

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote the oxidation of CO and VOC to CO₂ and water at temperatures approximately 50 percent lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F.

The efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO and VOC oxidation will occur at any temperature above roughly 500°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time, which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. Oxidation catalyst systems are typically designed for a CO oxidation efficiency of 80 to 90 percent. The efficiency of VOC oxidation is approximately 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies. Oxida-

tion catalysts are also subject to masking and/or blinding by fly ash contained in the exhaust stream of a pulverized coal boiler.

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOC. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. The catalyst will further oxidize sulfur compounds that have been oxidized to SO_2 in the combustion process to SO_3 . If ammonia is also present as a result of an SCR control system, SO_3 and ammonia will react to form ammonium bisulfate or ammonium sulfate PM. If ammonia is not present, SO_3 will combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of either ammonium bisulfate/ammonium sulfate PM or H_2SO_4 mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing significant amounts of sulfur. There are no known installations of catalytic oxidation technology to control CO and VOC emissions from coal-fired boilers.

5.5.1.2 Technical Feasibility

The only CO and VOC control technology considered technically feasible for pulverized coal-fired boilers is combustion controls. Neither thermal nor catalytic oxidation is considered technically feasible for the TEC supercritical pulverized coal main boiler. To avoid fouling, a thermal oxidizer would need to be located downstream of the fabric filter. Thermal oxidation at this location would require a substantial combustion chamber to increase the temperature of the main boiler exhaust gas to the required thermal oxidizer combustion temperature of 1,500°F. Without subsequent cooling, this substantial increase in exhaust volume would prevent the proper operation of the proposed downstream control systems (i.e., FGD and WESP), which are designed for a much lower exhaust flow rate.

Similarly, an oxidation catalyst system would also need to be located downstream of the fabric filter to prevent fly ash scouring of the catalyst bed. Although the required exhaust stream temperature is lower for catalytic oxidation (approximately 750°F) compared to

thermal oxidation (approximately 1,500°F), the exhaust stream would still need to be reheated to achieve efficient CO and VOC oxidation. The substantial increase in SO₃ due to the oxidation of SO₂ would also lead to a significant increase in ammonium sulfate PM and/or H₂SO₄ mist emissions. Oxidation catalysts are susceptible to deactivation due to a variety of impurities. Due to the lack of operating experience and potential catalyst deactivation, the performance and reliability of oxidation catalyst controls applied to coal-fired boilers is unknown.

As noted previously, there are no known installations of either thermal or catalytic oxidation technology to control CO and VOC emissions from coal-fired boilers. Accordingly, the only technically feasible CO and VOC control technology for coal-fired boilers is good combustion design and operation.

5.5.1.3 Proposed CO and VOC BACT

Table 5-7 provides a summary of recent CO and VOC BACT determinations for coal-fired utility boilers. The database includes CO emission limits between 0.10 lb/MMBtu (see, e.g., Louisville Gas and Electric, Desert Rock, and Thoroughbred Generating Station) and 0.20 lb/MMBtu (e.g., Prairie Energy Power Plant and Franklin Energy Coal Project). A majority of the CO BACT determinations are in the range of 0.15 to 0.16 lb/MMBtu. VOC emission rates were typically in the range of 0.003 to 0.004 lb/MMBtu, depending on the corresponding fuel heating value.¹ In all cases, combustion design and operation was determined to represent BACT for CO and VOC control.

TEC is proposing CO BACT emission limits of 0.15 lb/MMBtu (30-day average based on CEMS data) for all solid fuel blends and 0.13 lb/MMBtu (based on a stack test) for coal only. The proposed VOC BACT limit is 0.0036 lb/MMBtu based on the applicable AP-42 emission factor and projected fuel heating value. These emission limits are

¹It appears that VOC emissions for all coal-fired units listed in the RBLC database were calculated using the AP-42 emission factor of 0.06 lb VOC per ton of coal burned (AP-42 Table 1.1-19). Therefore, VOC emissions on a lb/MMBtu basis will vary depending on heating content of the fuel.

Table 5-7. Summary of Coal-Fired Power Plant CO and VOC BACT Determinations (Page 1 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limits	
							CO (lb/MMBtu)	VOC (lb/MMBtu)
Springerville Generating Station (Tucson Electric Power Co)	AZ	Apr 2002	3, 4	PC	800	VOC limit = 0.06 lb/ton coal combusted Combustion controls	0.135	See comment
Plum Point Energy Station (Plum Point Energy Associates, LLC)	AR	8/20/03	1	PC	800	Combustion controls	0.160	0.020
Comanche Plant Unit 3 (Public Service Company of CO)	CO	Jul 2005	3	PC	750	Combustion controls	0.130	0.004
Xcel Energy	CO	Jul 2005		PC	750	Combustion controls	0.150	0.004
Indiantown Cogeneration Plant (Indiantown Cogeneration, LP)	FL	1995	1	PC	330		0.110	0.004
Seminole Electric Unit 3	FL	Aug 2006	3	SCPC	750	Coal only, combustion controls	0.150	0.004
Stanton Energy Center (MUA/OUC/FMPA)	FL	1996	2	PC	468		0.150	
Longleaf Energy Station (LS Power)	GA	Pending	1, 2	PC	600	CO 30-day rolling average VOC 3-hour average	0.150	0.004
Holcomb Generating Station (Sand Sage Power, LLC)	KS	4/5/04	2	PC	660	Combustion controls	0.150	0.004
Louisville Gas & Electric	KY	Jan 2006		SCPC	750	CO 30-day average, VOC 3-hour average	0.100	0.003
Thoroughbred Generating Station (Thoroughbred Generating Co, LLC)	KY	May 2006	1,2	PC	1,500	Combustion controls	0.100	0.007
MidAmerican Energy Center Council Bluffs (MidAmerican Energy)	IA	6/17/03	4	SCPC	750	Combustion controls	0.154	0.004
Baldwin Expansion (Dynegy)	IL	Pending	1,2	PC	750		0.154	
Dellman Unit 4 (City Water Light & Power - Springfield, IL) (Not subject to SO ₂ or NO _x BACT)	IL	Draft (Feb 2006)	4	PC	250	CO 3-hour average	0.120	
Prairie State (Prairie State Generating Co, LLC)	IL	Apr 2005	1,2	PC	1,500	Combustion controls	0.120	0.004
Prairie Energy Power Plant (Corn Belt Energy Corporation)	IL	12/17/02	1	PC	91	CO 30-day rolling average	0.200	0.007
Franklin Energy Coal Project (Illinois Energy Group)	IL	Pending	1,2	PC	680		0.200	
NRG Energy (Big Cajun II) (Louisiana Generating, LLC)	LA	Aug 2005	2	SCPC	575	Combustion controls	0.135	0.015
KCP&L Latan Generating	MO	Jan 2006		PC	850	Combustion controls	0.140	0.004
Weston Bend Generating Station (Great Plains Power Company)	MO	Nov 2001	1	PC	820		0.160	0.004
Southwest Power Station (City Utilities of Springfield)	MO	12/15/04	2	PC	275	Combustion controls	0.160	0.004
Roundup Power Project (Bull Mountain Development Co)	MT	7/21/03	1, 2	PC	780	Combustion controls	0.150	0.003
Rocky Mountain Power (Rocky Mountain Power, Inc.)	MT	6/11/02	1	PC	113		0.150	0.003
Montana Dakota Utilities	ND	Jun 2005		PC	220	3-hour average	0.154	0.005
Whelan Energy Center (Hastings Utilities)	NE	Mar 2004	1	PC	220	Combustion controls	0.150	
Nebraska City Unit 2 (Omaha Public Power District)	NE	Mar 2005	2		660	Combustion controls CO 3-hour average	0.160	0.0034

Table 5-7. Summary of Coal-Fired Power Plant CO and VOC BACT Determinations (Page 2 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limits	
							CO (lb/MMBtu)	VOC (lb/MMBtu)
Newmont TS Power Plant (Newmont NV Energy Investment, LLC)	NV	May 2005		PC	200	Combustion controls 24-hour rolling average	0.150	NA
Desert Rock Energy Facility (Steag Power, LLC)	NM	Pending	1, 2	PC	750	24-hour averages	0.100	0.03
Cottonwood Energy Center (Chaco Valley Energy, LLC)	NM	Pending	1	PC	495		0.140	0.0072
Mustang Generating Station (Chaco Valley Energy, LLC)	NM	Pending	1	PC	330		0.160	0.01
Santee Cooper Cross (Not subject to SO ₂ or NO _x BACT)	SC	2/5/04	3,4	PC	660	3-hour averages	0.160	0.0024
Calaveras Plant Spruce Unit 2 (Not subject to SO ₂ or NO _x BACT)	TX	12/05	2	PC	750		0.150	0.0025
City Public Service	TX	Sep 2005		PC	750	Combustion controls	0.150	0.0036
Sandy Creek Energy (LS Power)	TX	Pending	1	PC	500		0.150	0.0036
Intermountain Power (Intermountain Power Service Corp)	UT	10/15/04	3	PC	950	Combustion controls	0.150	0.0027
Weston Unit 4 (Wisconsin Public Service Company)	WI	Oct 2004	1	PC	500		0.150	0.0036
Elm Road Generating Station (We Energy - formerly WEPCO)	WI	1/14/04	1,2	SCPC	1,230	Combustion controls	0.120	0.0035
Public Service Corp Wausau	WI	Oct 2004		SCPC	500	Combustion controls	0.150	0.0036
Longview Power (Longview Power, LLC)	WV	3/2/04	1	PC	600	Combustion controls	0.110	0.004
WYGEN II (Black Hills Corporation)	WY	Sep 2002	1	PC	500		0.150	0.01
Black Hills (Black Hills Corporation)	WY	Jun 1999	1	PC	80		0.150	
Two Elk (Two Elk Generation Partners, L.P.)	WY	May 2003	1	PC	250		0.135	
Minimum							0.100	0.002
Maximum							0.200	0.030
Average							0.144	0.006
Median							0.150	0.004

Source: ECT, 2007.

consistent with good combustion design and operation. Although the RBLC database includes units that have been permitted with lower CO emission rates, there are two important distinctions between the previously permitted units and TEC's proposed CO BACT limits: (1) TEC is proposing to achieve a lower NO_x emission limit; and (2) TEC is proposing to demonstrate compliance with the 30-day average CO BACT limit using a continuous CO emissions monitoring system.

As noted previously, boiler combustion design and operation requires a balancing of the competing goals to minimize the formation of both NO_x and CO/VOC. Combustion modifications designed to minimize CO/VOC emissions (e.g., higher combustion temperatures and more excess oxygen) will increase NO_x formation. Conversely, combustion modifications designed to minimize NO_x formation will result in increased CO/VOC emissions. As noted in Section 5.3.1.4, the proposed TEC main boiler NO_x BACT emission limit is lower than any permitted coal-fired power plant in the United States. Achieving the proposed NO_x BACT limit, while at the same time achieving the most aggressive CO emission limits listed in the RBLC database, is not technically feasible under all boiler operating conditions. Units listed in the RBLC database with CO emission limits below 0.15 lb/MMBtu all had NO_x limits greater than the NO_x BACT limit proposed by TEC.

Although continuous CO monitoring is not required by regulation, TEC is proposing to demonstrate compliance with the CO BACT limit using a CO CEMS.² An emission rate of 0.15 lb/MMBtu is equivalent to a CO concentration of approximately 180 ppmvd at 3-percent oxygen. To achieve this controlled CO emission rate, the main boiler will need to achieve combustion efficiencies (i.e., fuel carbon conversion to CO₂) of approximately 99.9 percent. Furthermore, because CO emissions will be monitored on a continuous basis rather than a one-time stack test, these combustion efficiencies must be achieved un-

²TEC finds no regulatory requirement to demonstrate compliance with the CO emission limit using CO CEMS. The Florida air pollution control regulations do not require continuous CO emissions monitoring. The applicable federal new source performance standard (40 CFR Part 60 Subpart Da) requires continuous monitoring for SO₂, NO_x, and opacity or PM, but does not require continuous monitoring of CO.

der all normal boiler operating conditions, including load changes and low-load operations. TEC did not identify any other units in the RBLC database that proposed demonstrating compliance with the CO BACT limit on a continuous basis.

The proposed CO and VOC BACT emission limits of 0.15/0.13 and 0.0036 lb/MMBtu, respectively, are consistent with the recent BACT determinations and should be achievable while meeting the proposed NO_x BACT limit. The proposed CO BACT emission limits are also consistent with the limits recently proposed by GEPD for the Longleaf Energy Facility and by FDEP for Seminole Generating Station Unit 3. CO and VOC BACT emission limits proposed for the TEC supercritical pulverized coal main boiler are summarized as follows:

- CO Emission Limit (all solid fuel blends)—0.15 lb/MMBtu.
 - Averaging Period—30-day rolling average.
 - Compliance Method—CO CEM.
- CO Emission Limit (coal only)—0.13 lb/MMBtu.
 - Averaging Period—Stack test duration.
 - Compliance Method—Stack test using EPA reference methods.
- VOC Emission Limit—0.0036 lb/MMBtu.
 - Averaging Period—Stack test duration.
 - Compliance Method—Initial stack test using EPA reference methods, and continuous compliance based on CO CEMS.

5.5.2 AUXILIARY BOILER

The formation mechanism of CO and VOC, available control technologies, and control technology technical feasibility described for the supercritical pulverized coal main boiler also generally apply to the auxiliary boiler.

The only CO and VOC control technology considered technically feasible for the TEC oil-fired auxiliary boiler is combustion controls.

Good combustion design and operation and constraints on annual operations are proposed as CO and VOC BACT for the auxiliary boiler. CO and VOC BACT emission limits proposed for the TEC auxiliary boiler is summarized as follows:

- Emission Limits—0.08 lb/MMBtu (CO) and 0.0054 lb/MMBtu (VOC).
- Averaging Period—Stack test duration.
- Compliance Method—Stack test using EPA reference methods.
- Annual Heat Input—328,500 MMBtu/yr.
- Averaging Period—Calendar year.
- Compliance Method—Fuel consumption monitoring.

5.5.3 EMERGENCY DIESEL ENGINES

The formation mechanism of CO and VOC, available control technologies, and control technology technical feasibility described for the supercritical pulverized coal main boiler also generally apply to the emergency diesel engines. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. Estimated CO and VOC emissions for both diesel engines are less than 1.0 and 0.1 tpy, respectively.

The only CO and VOC control technology considered technically feasible for the TEC oil-fired emergency diesel engines is combustion controls.

Good combustion design and operation and constraints on annual operations are proposed as CO and VOC BACT for the emergency diesel engines. The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for new nonroad CI engines. Subpart IIII limits CO emissions to 3.5 g/kW-hr for emergency generators purchased in 2007 or later. Subpart IIII limits the combination of NO_x and non-methane hydrocarbons (NMHC) emissions to 6.4 g/kW-hr for emergency generators purchased in 2007 or later. Subpart IIII also limits emissions of CO and the combination of NO_x and NMHC emissions from firewater pump diesel engines—the specific emission limits (Tier II or III) are dependent upon the model year in which the firewater pump die-

sel engine was manufactured. TEC will use emergency diesel engines that comply with the emission standards of NSPS Subpart IIII.

CO and VOC BACT proposed for the TEC emergency diesel engines are summarized as follows:

- Emission Limit—Applicable standards of NSPS Subpart IIII.
- Averaging Period—Per NSPS Subpart IIII.
- Compliance Method—Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.6 BACT ANALYSIS FOR H₂SO₄ MIST AND FLUORIDES

5.6.1 SUPERCRITICAL PC BOILER

Sulfur and fluorine in the coal will result in the creation of the acid gases H₂SO₄ mist and HF. Treatment of these compounds in the BACT analysis has been combined since they are both controlled using the same control technologies.

SO₂ and H₂SO₄ mist result from the oxidation of sulfur compounds in fuel. While most of the fuel sulfur is emitted as SO₂ following combustion, H₂SO₄ mist results when some of the fuel sulfur is oxidized to SO₃, which then reacts with moisture to form H₂SO₄ mist.

In addition, H₂SO₄ mist will potentially be created in the auxiliary boiler and diesel engines. However, since ULSD will be incorporated in these emission units, the emissions of H₂SO₄ mist will be extremely small.

Trace amounts of fluorine in the coal will primarily result in emissions of HF. Although other compounds of fluorine in the form of particulates may be created in the combustion process, these are expected to be negligible. Therefore, all fluorine has been assumed to

be converted to HF for purposes of calculating emissions and determining controlled emission rates.

5.6.1.1 Available H₂SO₄ and HF Control Technologies

Wet and Dry FGD

The same control technologies (i.e., dry and wet FGD) for reducing SO₂ emissions from the pulverized coal main boiler that were identified and discussed in Section 5.4 are also applicable for the control of H₂SO₄ mist and HF.

Wet Electrostatic Precipitator

A WESP employs the same mechanisms as a conventional dry ESP (i.e., charging, collection, and removal) to collect and remove fine PM from exhaust streams. A WESP, however, removes particles from the collecting electrodes by washing of the collection surface using water, rather than mechanically rapping the collector plates. WESPs are common in applications where the exhaust gas stream has a high moisture content, is below the dew point, or includes particulate that may be difficult to remove from a dry ESP. WESP is control technology used primarily to reduce PM/PM₁₀ emissions but has the co-benefit of also controlling H₂SO₄ and HF emissions.

5.6.1.2 Technical Feasibility and Ranking

Table 5-8 provides a summary of the technical feasibility and ranking of the available H₂SO₄ mist and HF.

Both dry and wet FGD, as well as WESP, are feasible control technologies for reducing H₂SO₄ mist and HF emissions from the supercritical pulverized coal main boiler. Although the dry FGD/WESP combination may be marginally better at controlling H₂SO₄ mist, this does not appear to be supported by the BACT levels for recent pulverized coal plant projects. With one exception, the lowest H₂SO₄ mist BACT emission rate of 0.004 lb/MMBtu (approximately 1.6 ppmvd at 3-percent oxygen) is achieved for both wet and dry FGD systems. The one exception is the Southwest Power Station in Missouri, which combusts PRB coal exclusively.

Table 5-8. Ranking of Available H₂SO₄ mist and HF Control Technologies—Main Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency* (%)
Dry FGD and WESP	Yes	98
Wet FGD and WESP	Yes	97.5
Dry FGD	Yes	92
Wet FGD	Yes	50

*Control efficiencies vary depending on the level of uncontrolled H₂SO₄ mist and HF emissions.

Source: ECT, 2007.

The test method used to measure H₂SO₄ emission rates (EPA Test Method 8) has proven to be problematic on coal-fired boilers. For example, interfering agents with Method 8 include fluorides and free ammonia. In fact, Method 8 states that if “any of these interfering agents is present... alternative methods, subject to the approval of the Administrator, are required.” One alternative test method that has been proposed to measure H₂SO₄ emissions from stationary sources is the controlled condensation method (Method 8A); however, certain flue gas characteristics may also result in measurement biases with this method.³

Because of the difficulties associated with measuring low H₂SO₄ emission rates, equipment vendors have not been willing to guarantee H₂SO₄ emissions below 1.0 ppmvd at 3-percent oxygen. Based on information from equipment vendors, an emission rate in the range of 1 to 2 ppmvd at 3-percent oxygen represents the practical analytical detection limit of Methods 8 and 8A on a coal-fired boiler, depending on the specific flue gas characteristics. Although the combination of fabric filter + wet FGD + WESP will provide the most effective H₂SO₄ control, TEC does not consider it appropriate to propose an emission limit below the practical detection limit of the compliance test method.

5.6.1.3 Evaluation of Control Technologies

The combination of dry FGD and WESP is shown to be slightly more effective (approximately 0.5 percent better) at controlling H₂SO₄ mist and HF emissions compared to a wet FGD/WESP system. However, since the application of wet FGD/WESP represents the top BACT control technology for SO₂, proportionately many more tons per year of SO₂ are reduced by use of the wet FGD/WESP system than H₂SO₄ mist and HF by a dry FGD/WESP. The small difference in H₂SO₄ mist and HF control efficiency between the wet FGD/WESP and dry FGD/WESP control systems does not justify replacement of the

³See, Blythe, G., *et al.* “Improvements to the Controlled Condensation measurement method for Sulfuric Acid,” presented at the EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: The Mega Symposium. Atlanta, GA, August 16 – 20, 1999. See also, Blythe, G., *et al.* “Flue Gas sulfuric Acid Measurement Method Improvements.”

wet FGD/WESP control system, with a very high SO₂ removal efficiency, with the dry FGD/WESP technology that has a significantly lower SO₂ removal efficiency.

5.6.1.4 Proposed H₂SO₄ and HF BACT

Table 5-9 provides a summary of recent H₂SO₄ mist and HF BACT determinations for coal-fired boilers.

TEC proposes a H₂SO₄ BACT emission limit of 0.004 lb/MMBtu. Compliance with the H₂SO₄ emission rate would be demonstrated based on an initial compliance test using EPA Reference Method 8 (or an alternative test method approved by FDEP) and ongoing compliance with the applicable SO₂ and PM₁₀ emission limits. An emission rate of 0.004 lb/MMBtu is equivalent to a H₂SO₄ concentration in the flue gas of approximately 1.6 ppmvd at 3-percent oxygen. Assuming an uncontrolled H₂SO₄ emission rate of 0.12 lb/MMBtu (calculated based on 2.25-percent SO₂ to SO₃ conversion in the boiler and SCR), the combination of emission control technologies will need to achieve an average removal efficiency of approximately 97 percent to ensure compliance with the proposed emission limit.

Use of wet FGD and WESP control technologies are proposed as H₂SO₄ mist and HF BACT for the main boiler. H₂SO₄ mist and HF BACT emission limits proposed for the TEC main boiler are summarized as follows:

- Emission Limits—0.004 lb/MMBtu (H₂SO₄) and 0.00047 lb/MMBtu (HF).
- Averaging Period—Stack test duration.
- Compliance Method—Stack test using EPA reference methods.

5.6.2 AUXILIARY BOILER

Only negligible amounts of H₂SO₄ mist and HF will be emitted from the auxiliary boiler. The only H₂SO₄ mist control technology considered technically feasible for the auxiliary boiler is the use of ULSD fuel oil. No specific technology for the control of fluorides from the oil-fired combustion sources was identified. However, it is reasonable to conclude that fluorine will be present in only trace amounts in the highly refined ULSD

Table 5-9 Summary of Coal-Fired Power Plant H₂SO₄ Mist and HF BACT Determinations

(Page 1 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limit	
							H ₂ SO ₄ (lb/MMBtu)	HF (lb/MMBtu)
Springerville Generating Station (Tucson Electric Power Co)	AZ	Apr 2002	3, 4	PC	800	Cobenefit controls DFGD/fabric filter	0.6000	0.00044
Plum Point Energy Station (Plum Point Energy Associates, LLC)	AR	8/20/03	1	PC	800	DFDG/fabric filter	0.0061	0.00044
Comanche Plant Unit 3 (Public Service Company of CO)	CO	Jul 2005	3	PC	750	As HF	0.0042	0.00049
Xcel Energy	CO	Jul 2005		PC	750		0.0029	0.00050
Indiantown Cogeneration Plant (Indiantown Cogeneration, LP)	FL	1995	1	PC	330	Fabric filter	0.0004	0.00150
Seminole Electric Unit 3	FL	Aug 2006	3	SCPC	750	WFGD/WESP		0.00023
Stanton Energy Center (MUA/OU/CMPA)	FL	1996	2	PC	468			
Longleaf Energy Station (LS Power)	GA	Pending	1, 2	PC	600	DFDG/fabric filter	0.0001	0.00095
Holcomb Generating Station (Sand Sage Power, LLC)	KS	4/5/04	2	PC	660		0.0040	NA
Louisville Gas & Electric	KY	Jan 2006		SCPC	750	WFGD	0.0038	0.00022
Thoroughbred Generating Station (Thoroughbred Generating Co, LLC)	KY	May 2006	1,2	PC	1,500	WDGD/WESP	0.0050	0.00016
MidAmerican Energy Center Council Bluffs (MidAmerican Energy)	IA	6/17/03	4	SCPC	750	Cobenefit controls	0.0042	0.00090
Baldwin Expansion (Dynegy)	IL	Pending	1,2	PC	750			
Dellman Unit 4 (City Water Light & Power - Springfield, IL) (Not subject to SO ₂ or NO _x BACT)	IL	Draft (Feb 2006)	4	PC	250	3-hour average	0.0050	
Prairie State (Prairie State Generating Co, LLC)	IL	Apr 2005	1,2	PC	1,500	WFDG/WESP	0.0050	0.00026
Prairie Energy Power Plant (Corn Belt Energy Corporation)	IL	12/17/02	1	PC	91	WFDG/WESP		
Franklin Energy Coal Project (Illinois Energy Group)	IL	Pending	1,2	PC	680			
NRG Energy (Big Cajun II) (Louisiana Generating, LLC)	LA	Aug 2005	2	SCPC	575	WFGD/sorbent injection	0.0075	0.00056
KCP&L Latan Generating	MO	Jan 2006		PC	850		0.0072	
Weston Bend Generating Station (Great Plains Power Company)	MO	Nov 2001	1	PC	820			
Southwest Power Station (City Utilities of Springfield)	MO	12/15/04	2	PC	275	Synthetic minor for HAPs	0.0002	0.00037
Roundup Power Project (Bull Mountain Development Co)	MT	7/21/03	1, 2	PC	780		0.0064	
Rocky Mountain Power (Rocky Mountain Power, Inc.)	MT	6/11/02	1	PC	113		0.0063	0.00051
Montana Dakota Utilities	ND	Jun 2005		PC	220			0.00053

Table 5-9 Summary of Coal-Fired Power Plant H₂SO₄ Mist and HF BACT Determinations

(Page 2 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limit	
							H ₂ SO ₄ (lb/MMBtu)	HF (lb/MMBtu)
Whelan Energy Center (Hastings Utilities)	NE	Mar 2004	1	PC	220		0.0004	0.00040
Nebraska City Unit 2 (Omaha Public Power District)	NE	Mar 2005	2		660	HF 3-hour average	0.0042	0.00040
Newmont TS Power Plant (Newmont NV Energy Investment, LLC)	NV	May 2005		PC	200			
Desert Rock Energy Facility (Steag Power, LLC)	NM	Pending	1, 2	PC	750	WFGD/sorbent injection 3-hour averages	0.0040	0.00024
Cottonwood Energy Center (Chaco Valley Energy, LLC)	NM	Pending	1	PC	495		0.0600	0.14000
Mustang Generating Station (Chaco Valley Energy, LLC)	NM	Pending	1	PC	330		0.0720	0.16000
Santee Cooper Cross (Not subject to SO ₂ or NO _x BACT)	SC	2/5/04	3,4	PC	660			
Calaveras Plant Spruce Unit 2 (Not subject to SO ₂ or NO _x BACT)	TX	12/05	2	PC	750		0.0037	
City Public Service	TX	Sep 2005		PC	750	WFGD	0.0037	0.00080
Sandy Creek Energy (LS Power)	TX	Pending	1	PC	500		0.0070	
Intermountain Power (Intermountain Power Service Corp)	UT	10/15/04	3	PC	950	Cobenefit controls	0.0044	0.00050
Weston Unit 4 (Wisconsin Public Service Company)	WI	Oct 2004	1	PC	500		0.0050	0.00022
Elm Road Generating Station (We Energy - formerly WEPCO)	WI	1/14/04	1,2	SCPC	1,230	WESP	0.0100	0.00088
Public Service Corp Wausau	WI	Oct 2004		SCPC	500	Sorbent onjection/HF	0.0050	0.00022
Longview Power (Longview Power, LLC)	WV	3/2/04	1	PC	600	Dry sorbent injection, no WESP	0.0075	0.00001
WYGEN II (Black Hills Corporation)	WY	Sep 2002	1	PC	500			
Black Hills (Black Hills Corporation)	WY	Jun 1999	1	PC	80			
Two Elk (Two Elk Generation Partners, L.P.)	WY	May 2003	1	PC	250			
Minimum							0.0001	0.00001
Maximum							0.6000	0.16000
Average							0.0285	0.01199
Median							0.0050	0.00047

Source: ECT, 2007.

The exclusive use of ULSD fuel oil and constraints on annual operations are proposed as H₂SO₄ mist and HF BACT for the auxiliary boiler. H₂SO₄ mist and HF BACT proposed for the TEC auxiliary boiler are summarized as follows:

- Emission Limit—Exclusive use of ULSD fuel oil.
- Compliance Method—Supplier certifications of fuel oil sulfur content.
- Annual Heat Input—328,500 MMBtu/yr.
- Averaging Period—Calendar year.
- Compliance Method—Fuel consumption monitoring.

5.6.3 EMERGENCY DIESEL ENGINES

Only negligible amounts of H₂SO₄ mist and HF will be emitted from the emergency diesel engines. The only H₂SO₄ mist and HF control technology considered technically feasible for the emergency diesel engines is the use of ULSD fuel oil.

The exclusive use of ULSD fuel oil and constraints on annual operations are proposed as H₂SO₄ mist and HF BACT for the emergency diesel engines. H₂SO₄ mist and HF BACT proposed for the TEC emergency diesel engines are summarized as follows:

- Emission Limit—Exclusive use of ULSD fuel oil.
- Compliance Method—Supplier certifications of fuel oil sulfur content.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.7 BACT ANALYSIS FOR PM/PM₁₀

PM is classified by particle size and is defined by the test methods used to measure stack emissions. Filterable PM is measured using EPA Reference Methods 5, 5B, or 17 which capture particles greater than 0.3 micron in size using a filter that is weighed prior to and following the stack test to determine the gain in weight. In Method 5, the filter is located in the sampling train external to the stack and maintained at a temperature of 248°F. A

variation of Method 5 is Method 5B, which maintains the filter temperature at 320°F to exclude H₂SO₄ PM. Method 17 places the filter in the stack and therefore collects PM at the prevailing stack temperature. Filterable PM₁₀ is measured using either EPA Reference Methods 201 or 201A. Both of these test methods collect filterable PM with a nominal aerodynamic diameter of 10 microns or less using an in-stack cyclone and filter system. All of the filterable PM test methods, commonly referred to as front-half PM, determine the mass of PM that condenses at or above the filter temperature.

EPA also includes condensable PM as a component of PM₁₀. Condensable PM is collected using EPA Reference Method 202 by passing the filtered sample gas stream through a series of chilled water-filled impingers to maintain an impinger outlet sample gas temperature of 68°F or less. Following sampling, the impinger solution is purged with nitrogen and extracted with methylene chloride. The organic and water fractions are then evaporated and the residues weighed to determine the mass of condensable PM. Since the impingers are located in the sampling train downstream of the filter, condensable PM is also referred to as back-half particulate.

In summary, PM includes the filterable portion of PM as measured by EPA Reference Methods 5, 5B, or 17. PM₁₀ includes filterable PM less than 10 microns as measured by EPA Reference Methods 201 or 201A and condensable PM as measured by EPA Reference Method 202. Since PM₁₀ includes condensable particulate and PM does not, PM emission sources will have higher PM₁₀ emissions compared to PM. For fossil-fuel combustion sources, PM₁₀ emission rates are approximately double that of PM emissions. Accordingly, the distinction between PM and PM₁₀ is important when assessing BACT for fossil-fuel fired combustion sources.

5.7.1 SUPERCRITICAL PC BOILER

PM/PM₁₀ emissions resulting from the combustion of coal are due to the oxidation of ash and sulfur contained in these fuels. PM/PM₁₀ emission rates depend on coal composition (i.e., ash content), boiler design and operation, and emission control equipment. Uncontrolled PM/PM₁₀ emissions from coal-fired boilers include the ash from fuel combustion,

unburned carbon resulting from incomplete combustion, and condensable compounds. Pulverized coal-fired boilers achieve a high combustion efficiency resulting in PM/PM₁₀ emissions that are primarily comprised of inorganic ash residues.

Ash generated by the combustion of coal will exit the boiler as either bottom ash or fly ash. Fly ash is entrained in the boiler exhaust gas stream and will be discharged to the atmosphere unless removed by emission control equipment. Bottom ash is the noncombustible slag or residue remaining after the coal is combusted. Bottom ash is removed mechanically from the boiler and is handled and processed as a solid combustion byproduct.

5.7.1.1 Available PM/PM₁₀ Control Technologies

Available technologies used for controlling PM/PM₁₀ from pulverized coal fired boilers include the following:

- Centrifugal collectors.
- ESPs.
- WESP.
- Fabric filters or baghouses.
- Wet scrubbers.

Centrifugal Collectors

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large sized (greater than 10 microns) particles. Particles generated from natural gas combustion are typically less than 1.0 micron in size.

Electrostatic Precipitators

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes.

Wet Electrostatic Precipitators

WESPs remove particles from a gas stream using the same mechanisms as described above for ESPs. A WESP, however, removes particles from the collecting electrodes by washing of the collection surface using water, rather than mechanically rapping the collector plates. WESPs are common in applications where the exhaust gas stream has a high moisture content, is below the dew point, or includes particulate that may be difficult to remove from a dry ESP.

Fabric Filter

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM/PM₁₀ is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot (cfm-ft²).

Wet Scrubbers

Wet scrubbers remove PM/PM₁₀ from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM/PM₁₀ must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high-pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drops

for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

5.7.1.2 Technical Feasibility and Ranking

All of the available PM/PM₁₀ control technologies described previously are technically feasible for the supercritical pulverized coal main boiler. Table 5-10 provides a summary of the technical feasibility and ranking of the available PM/PM₁₀ control technologies. As shown, fabric filter technology provides the highest control efficiency.

5.7.1.3 Evaluation of Control Technologies

TEC proposes to install the PM/PM₁₀ control technology identified as having the highest control efficiency—fabric filter. The TEC main boiler emission control system will also include a wet FGD and WESP for additional PM/PM₁₀ control. The economic and energy impacts associated with the installation and operation of these control technologies are considered reasonable. There are also no significant collateral environmental issues that would justify rejection of these control technologies as BACT.

5.7.1.4 Proposed PM/PM₁₀ BACT

Table 5-11 provides a summary of recent PM BACT determinations for coal-fired utility boilers.

TEC will employ a range of fuels and therefore differs from mine-mouth projects such as the New Mexico Desert Rock project, which will have little variability in the fuel characteristics. In its PM/PM₁₀ BACT analysis for the proposed Seminole Generating Station Unit 3, FDEP concluded that a filterable PM emission limit of 0.013 lb/MMBtu represented an aggressive limit at the low end of recent BACT determinations.

TEC proposes PM and PM₁₀ BACT emission rates of 0.013 and 0.025 lb/MMBtu, respectively. These limits reflect the expected performance of the fabric filter, wet FGD,

Table 5-10. Ranking of Available PM/PM₁₀ Control Technologies—Main Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency* (%)
Fabric filter	Yes	99.5
ESP	Yes	99
WESP	Yes	99
Wet venturi scrubber	Yes	95
Cyclone collector	Yes	80 to 90

*Control efficiencies vary depending on the level of uncontrolled PM/PM₁₀ emissions.

Source: ECT, 2007.

Table 5-11. Summary of Coal-Fired Power Plant PM BACT Determinations (Page 1 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limit PM/PM ₁₀ (lb/MMBtu)
Springerville Generating Station (Tucson Electric Power Co)	AZ	Apr 2002	3, 4	PC	800	PM 10 (filterable), fabric filter 15-percent opacity	0.015
Plum Point Energy Station (Plum Point Energy Associates, LLC)	AR	8/20/03	1	PC	800	Fabric filter	0.018
Comanche Plant Unit 3 (Public Service Company of CO)	CO	Jul 2005	3	PC	750	PM fabric filter, 10-percent opacity	0.013
Xcel Energy	CO	Jul 2005		PC	750	PM (filterable), fabric filter 3-hour average	0.020
Indiantown Cogeneration Plant (Indiantown Cogeneration, LP)	FL	1995	1	PC	330	Fabric filter	0.018
Seminole Electric Unit 3	FL	Aug 2006	3	SCPC	750	Filterable (100-percent coal), ESP/WESP 20-percent opacity	0.015
Stanton Energy Center (MUA/OUC/FMPA)	FL	1996	2	PC	468	Fabric filter	0.018
Longleaf Energy Station (LS Power)	GA	Pending	1, 2	PC	600	Fabric filter	0.015
Holcomb Generating Station (Sand Sage Power, LLC)	KS	4/5/04	2	PC	660	Fabric filter PM, 20-percent opacity PM ₁₀ : 6 test runs of 120 min each	0.012
Louisville Gas & Electric	KY	Jan 2006		SCPC	750	Pulse jet fabric filter, 20-percent opacity (0.015 lb/MMBtu filterable)	0.018
Thoroughbred Generating Station (Thoroughbred Generating Co, LLC)	KY	May 2006	1,2	PC	1,500	ESP/WESP 20-percent opacity	0.018
MidAmerican Energy Center Council Bluffs (MidAmerican Energy)	IA	6/17/03	4	SCPC	750	PM Filterable 40-percent opacity	0.018
Baldwin Expansion (Dynergy)	IL	Pending	1,2	PC	750		0.018
Dellman Unit 4 (City Water Light & Power - Springfield, IL) (Not subject to SO ₂ or NO _x BACT)	IL	Draft (Feb 2006)	4	PC	250	3-hour average	0.015
Prairie State (Prairie State Generating Co, LLC)	IL	Apr 2005	1,2	PC	1,500	ESP, 20-percent opacity	0.015
Prairie Energy Power Plant (Corn Belt Energy Corporation)	IL	12/17/02	1	PC	91	ESP, 20-percent opacity	0.020
Franklin Energy Coal Project (Illinois Energy Group)	IL	Pending	1,2	PC	680		0.020
NRG Energy (Big Cajun II) (Louisiana Generating, LLC)	LA	Aug 2005	2	SCPC	575	Fabric filter, ESP	0.015
KCP&L Latan Generating	MO	Jan 2006		PC	850	Filterable PM, 20-percent opacity	0.018
Weston Bend Generating Station (Great Plains Power Company)	MO	Nov 2001	1	PC	820		0.018
Southwest Power Station (City Utilities of Springfield)	MO	12/15/04	2	PC	275	Fabric filter	0.018
Roundup Power Project (Bull Mountain Development Co)	MT	7/21/03	1, 2	PC	780	PM (filterable)	0.012
Rocky Mountain Power (Rocky Mountain Power, Inc.)	MT	6/11/02	1	PC	113		0.012
Montana Dakota Utilities	ND	Jun 2005		PC	220	PM filterable	0.017

Table 5-11. Summary of Coal-Fired Power Plant PM BACT Determinations (Page 2 of 2)

Plant	State	Permit Date	Unit Number	Boiler Type	Generation Capacity (MW)	Comments	BACT Limit PM/PM ₁₀ (lb/MMBtu)
Whelan Energy Center (Hastings Utilities)	NE	Mar 2004	1	PC	220	Fabric filter, ≥20-percent opacity	0.018
Nebraska City Unit 2 (Omaha Public Power District)	NE	Mar 2005	2		660	Fabric filter 3-hour average	0.018
Newmont TS Power Plant (Newmont NV Energy Investment, LLC)	NV	May 2005		PC	200	Fabric filter PM ₁₀ filterable ≥20-percent opacity	0.012
Desert Rock Energy Facility (Steag Power, LLC)	NM	Pending	1, 2	PC	750	Fabric filter 24-hour average	0.01
Cottonwood Energy Center (Chaco Valley Energy, LLC)	NM	Pending	1	PC	495		0.02
Mustang Generating Station (Chaco Valley Energy, LLC)	NM	Pending	1	PC	330		0.018
Santee Cooper Cross (Not subject to SO ₂ or NO _x BACT)	SC	2/5/04	3,4	PC	660	3-hour average	0.015
Calaveras Plant Spruce Unit 2 (Not subject to SO ₂ or NO _x BACT)	TX	12/05	2	PC	750		0.022
City Public Service	TX	Sep 2005		PC	750	Fabric filter, includes condensible	0.022
Sandy Creek Energy (LS Power)	TX	Pending	1	PC	500		0.033
Intermountain Power (Intermountain Power Service Corp)	UT	10/15/04	3	PC	950	PM (filterable), fabric filter	0.013
Weston Unit 4 (Wisconsin Public Service Company)	WI	Oct 2004	1	PC	500		0.018
Elm Road Generating Station (We Energy - formerly WEPCO)	WI	1/14/04	1.2	SCPC	1,230	Fabric filter, 20-percent opacity	0.018
Public Service Corp Wausau	WI	Oct 2004		SCPC	500	PM (total), 40-percent opacity Fabric filter with condensible	0.02
Longview Power (Longview Power, LLC)	WV	3/2/04	1	PC	600	Fabric filter, 10-percent opacity PM ₁₀ with condensible	0.018
WYGEN II (Black Hills Corporation)	WY	Sep 2002	1	PC	500		0.012
Black Hills (Black Hills Corporation)	WY	Jun 1999	1	PC	80		0.02
Two Elk (Two Elk Generation Partners, L.P.)	WY	May 2003	1	PC	250		0.018
Minimum							0.010
Maximum							0.033
Average							0.017
Median							0.018

Source: ECT, 2007.

and WESP emission control equipment. As previously discussed, a higher emission limit is required for PM₁₀ due to the inclusion of condensable particulate. The proposed TEC main boiler PM and PM₁₀ BACT emission limits are lower than the 0.015- and 0.033-lb/MMBtu limits for PM and PM₁₀ recently proposed by the GEPD for the Long-leaf Energy Project. The proposed BACT limit for filterable PM is also consistent with the limit proposed by FDEP for Seminole Generating Station Unit 3. PM and PM₁₀ BACT emission limits proposed for the TEC main boiler are summarized as follows:

- Emission Limits—0.013 lb/MMBtu (PM) and 0.025 lb/MMBtu (PM₁₀); 20 percent (27 percent for not more than 6 minutes in any hour) (opacity).
- Averaging Period—Stack test duration.
- Compliance Method—EPA Reference Methods 5, 5B, or 17 (PM); EPA Reference Methods 201 or 201A, and 202 (PM₁₀); EPA Reference Method 9 (opacity).

Table 5-12 provides a summary of preliminary fabric filter design parameters.

5.7.2 AUXILIARY BOILER

The TEC 375-MMBtu (HHV) auxiliary boiler will be fired with ULSD fuel oil containing no more than 0.0015 percent sulfur by weight. The auxiliary boiler will also operate with a capacity factor of no more than 10 percent, which is equivalent to 876 hr/yr operation at design capacity.

The use of low ash fuel oil is considered to be the only technically feasible PM/PM₁₀ control technology for the oil-fired auxiliary boiler. The installation of add-on control equipment such as an ESP, fabric filter, or wet scrubber would result in excessive costs due to the low uncontrolled PM/PM₁₀ emission rates.

The exclusive use of ULSD fuel oil and constraints on annual operations are proposed as PM/PM₁₀ BACT for the auxiliary boiler. PM/PM₁₀ BACT proposed for the TEC auxiliary boiler is summarized as follows:

Table 5-12. Anticipated Fabric Filter Operating Parameters

Parameter	Unit	Estimated Design Value	Notes
Flue gas flow rate to fabric filter	acfm	2,937,838	Flue gas flow to the fabric filter depends on the fuel blend; design flow rate listed to the left is for the 100-percent Latin American coal
Inlet gas temperature	°F	275 to 325	
Inlet filterable particulate loading	lb/hr	67,192 (9.16 lb/MMBtu)	Based on Central Appalachian ash content of 14.04 percent and heating value of 12,258 Btu/lb
Outlet filterable particulate loading	lb/MMBtu lb/hr	0.013 97.2	Based on maximum heat input of 7,475 MMBtu/hr
Bag material	—	—	To be determined during detailed design
Bag diameter, length, number of bags	—	—	To be determined during detailed design
Number of modules and compartments per module	—	—	To be determined during detailed design
Air to cloth ratio	ft	Approximately 4	Final air-to-cloth ratio will be determined during detailed design
Pressure drop across baghouse	inches of water	8 to 9 (typical)	
Cleaning mechanism and cycle	—	Pulse Jet	

Note: acfm = actual cubic foot per minute.

Source: S&L, 2007.

- Emission Limits—0.014 lb/MMBtu (PM) and 0.023 lb/MMBtu (PM₁₀); 10-percent (opacity).
- Averaging Period—Stack test duration.
- Compliance Method—EPA Reference Methods 5, 5B, or 17 (PM); EPA Reference Methods 201 or 201A, and 202 (PM₁₀); EPA Reference Method 9 (opacity)
- Annual Heat Input—328,500 MMBtu/yr.
- Averaging Period—Calendar year.
- Compliance Method—Fuel consumption monitoring.

5.7.3 EMERGENCY DIESEL ENGINES

TEC will include a diesel engine-driven emergency generator rated at 1,640 kW and a diesel engine-driven firewater pump rated at 432 hp. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. Total estimated PM/PM₁₀ emissions for both diesel engines are less than 0.1 tpy.

The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for new nonroad CI engines. Subpart IIII limits PM/PM₁₀ emissions to 0.2 g/kW-hr for emergency generators purchased in 2007 or later. For firewater pump engines, Subpart IIII also limits PM/PM₁₀ emissions, but the emission limits (Tier II or Tier III) are dependent upon the model year in which the engine was manufactured. Emergency diesel engines purchased for TEC will comply with the applicable emission standards of NSPS Subpart IIII.

Compliance with the stringent NSPS Subpart IIII emission standards and limited annual operating hours is proposed as PM/PM₁₀ BACT for the TEC emergency generator and firewater pump diesel engines. PM/PM₁₀ BACT proposed for the TEC emergency diesel engines is summarized as follows:

- Emission Limit—Applicable standards of NSPS Subpart IIII.
- Averaging Period—Per NSPS Subpart IIII.

- Compliance Method—Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.7.4 COOLING TOWER

Cooling towers can employ either dry or wet cooling technologies. The heat dissipated from the TEC pulverized coal boiler can be cooled either by a source of air or water. An air-cooled condenser (ACC) uses air as the media for heat exchange, while a wet cooling tower employs water. Both of these technologies have been successfully used at recently constructed power plants.

5.7.4.1 Dry Cooling

An ACC is made up of a number of modules that are arranged in parallel lines. Within each module, there are many fin tube bundles. An axial flow, forced-draft fan is located within each module, and pushes the cooling air across the heat exchange area of the fin tubes. An ACC includes a supporting structure that would be substantially higher than a typical wet mechanical-draft cooling tower.

ACC technology would not maintain design plant output during the hot humid summers in North Florida during periods of peak demand. The efficiency of an ACC is directly related to the ambient air temperature. Although using water spray nozzles located upstream of the ACC inlet will cool the inlet air by the process of evaporation, this method is not effective in areas that experience high humidity levels, such as North Florida. Other disadvantages of ACC are potential scaling and corrosion from ambient salt concentration and high temperatures, high consumption of electricity for fan operation, significant source of noise, visual impacts, and high maintenance costs.

The clear advantage of an ACC is the significant reduction in water use and negligible PM/PM₁₀ emissions. Therefore, ACCs are closely evaluated for facilities located in areas which lack sufficient water resources. TEC proposes to use treated wastewater effluent as their water source and is located in a climate not conducive to using ACC technology.

5.7.4.2 Wet Cooling

Operation of conventional wet mechanical draft cooling tower operations will result in emissions of PM/PM₁₀. TEC will include a 20-cell cooling tower using recycled water from Buckeye as makeup water when available. Because of direct contact between the cooling water and ambient air, a small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential PM/PM₁₀ emissions because of the fine PM/PM₁₀ formed by crystallization of the dissolved solids contained in the droplet.

5.7.4.3 Available PM/PM₁₀ Control Technologies

Due to the technical issues associated with dry cooling, dry cooling tower technology is not considered technically feasible. Technical issues with the dry cooling technology include the inability to maintain plant design performance during hot humid periods, potential scaling and corrosion from ambient salt concentration and high temperatures, high consumption of electricity for fan operation, significant source of noise, visual impacts, and high maintenance costs.

The only feasible technology for controlling PM/PM₁₀ from wet cooling towers is the use of drift eliminators. Drift eliminators rely on inertial separation caused by airflow direction changes to remove water droplets from the air stream leaving the tower. The water droplets are returned to the cooling tower. Drift eliminator configurations include herringbone (blade-type), wave-form, and cellular (honeycomb) designs. Drift eliminator

materials of construction include ceramics; fiber-reinforced cement; metal; plastic; and wood fabricated into closely spaced slats, sheets, honeycomb assemblies, or tiles.

5.7.4.4 Proposed PM/PM₁₀ BACT

PM/PM₁₀ emissions from the TEC cooling tower will be controlled using high efficiency drift eliminators. The cooling tower will achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow. This cooling tower drift loss rate is consistent with recent FDEP BACT determinations (i.e., the FPL Turkey Point Unit 5 and West County Energy Center projects). PM/PM₁₀ BACT proposed for the TEC cooling tower is summarized as follows:

- Emission Limit—Use of high efficiency drift eliminators with a drift loss rate of no more than 0.0005 percent.
- Compliance Method—Cooling tower manufacturer certification.

5.7.5 MATERIAL HANDLING

TEC material handling and storage systems, including coal, fly ash, limestone, and by-products associated with the proposed TEC boiler, will generate fugitive and non-fugitive PM/PM₁₀ emissions. Fugitive emissions are emissions that cannot reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. In contrast, nonfugitive emissions are emissions that can reasonably be collected and subsequently passed through a stack, chimney, vent, or other functionally equivalent opening. Fugitive and nonfugitive PM/PM₁₀ emissions from material handling will be generated from three general source categories: transfer points, storage silos and piles, and roads.

5.7.5.1 Available PM/PM₁₀ Control Technologies

Transfer Points

Transfer points include truck loading/unloading, conveyor-to-conveyor drops, material transfers from reclaim hoppers to conveyors, and transfers from conveyors to storage silos. Particulate emissions will be generated as material drops through the transfer point. The potential to generate particulate emissions at a transfer point is a function of the rate at which the material flows through the transfer point, exposure to wind, and the mate-

rial's particle size and moisture content. Potential emissions from a transfer point can be reduced by decreasing the speed at which the material is transferred, decreasing the wind speed to which the material is exposed, or increasing the aggregate's moisture content by watering or chemical wetting agents. Transfer point emissions may be further reduced by enclosing the transfer operations within a structure, and exhausting the structure through a particulate control device (e.g., fabric filter).

Storage Silos and Piles

The transfer of materials to storage silos results in nonfugitive PM/PM₁₀ emissions due to the displacement of air from the silos. Fabric filters (also referred to as bin vent filters) are commonly used to control PM/PM₁₀ emissions from storage silos.

Fugitive PM/PM₁₀ emissions associated with storage piles include dust emissions produced by adding/removing material from the pile and from wind erosion. A combination of material drop controls (e.g., telescopic chutes), compaction, and dust suppression sprays (e.g., wetting) can be used to minimize fugitive emission from the material handling storage piles.

Roads

Vehicular traffic on paved and unpaved roads will generate fugitive PM/PM₁₀ emissions. Particulate emissions from roads can be controlled by sweeping, applying water as necessary, and limiting vehicle speeds.

5.7.5.2 Proposed PM/PM₁₀ BACT

A combination of good operating practices and fabric filters are proposed as PM/PM₁₀ BACT for the TEC material handling emission sources. Specific PM/PM₁₀ control measures proposed for the TEC material handling systems are as follows:

- Transfers Points—To the extent practical and appropriate, material handling transfer points will be enclosed and vented to fabric filters with a design outlet PM/PM₁₀ concentration of no more than 0.005 grain per dry standard cubic foot (gr/dscf). Where complete enclosure is not practical, partial en-

closure and/or wet dust suppression systems using water sprays or a chemical wetting agent will be employed.

- Storage Silos—Silos storing dry materials will be equipped with bin vent filters with a design outlet PM/PM₁₀ concentration of no more than 0.005 gr/dscf.
- Storage Piles—Water or chemical dust suppression will be applied to the active storage piles. Surface crusting agents will be applied to the inactive storage piles to minimize PM/PM₁₀ emissions due to wind erosion.
- Roads—The primary plant roadways will be paved. These roads will be watered or swept, as necessary, to control fugitive PM/PM₁₀ emissions. Traffic on unpaved roads will be kept to the minimum required for plant operations and will be watered, as necessary, to control fugitive PM/PM₁₀ emissions.

5.8 SUMMARY OF PROPOSED BACT

Table 5-13 provides a summary of the BACT proposed for TEC including the emission limit, averaging period, and compliance method.

Table 5-13. Summary of Proposed BACT

Emission Unit	Pollutant	Averaging Period	BACT Emission Limit	Compliance Method
Main boiler	NO _x	30-day rolling	0.05 lb/MMBtu	CEMS
		24-hour block*	373.8 lb/hr	CEMS
	SO ₂	30-day rolling	0.04 lb/MMBtu	CEMS
		24-hour block*	411.1 lb/hr	CEMS
	CO	30-day rolling	0.15 lb/MMBtu (all solid fuels)	CEMS
		Stack test duration	0.13 lb/MMBtu (coal only)	EPA reference methods
	VOC (as CH ₄)	Stack test duration	0.0036 lb/MMBtu	EPA reference methods
	H ₂ SO ₄ mist	Stack test duration	0.004 lb/MMBtu	EPA reference methods
Auxiliary boiler	HF	Stack test duration	0.00047 lb/MMBtu	EPA reference methods
	PM (filterable)	Stack test duration	0.013 lb/MMBtu	EPA reference methods
	PM ₁₀ (total)	Stack test duration	0.025 lb/MMBtu	EPA reference methods
	NO _x	Stack test duration	0.09 lb/MMBtu	EPA reference methods
		N/A	ULSD fuel oil	Fuel oil supplier certifications
	SO ₂	N/A	ULSD fuel oil	Fuel oil supplier certifications
	CO	Stack test duration	0.08 lb/MMBtu	EPA reference methods
	VOC (as CH ₄)	Stack test duration	0.0054 lb/MMBtu	EPA reference methods
	H ₂ SO ₄ Mist	N/A	ULSD fuel oil	Fuel oil supplier certifications
	HF	N/A	ULSD fuel oil	Fuel oil supplier certifications
	PM (filterable)	Stack test duration	0.014 lb/MMBtu	EPA reference methods
	PM ₁₀ (total)	Stack test duration	0.023 lb/MMBtu	EPA reference methods

Table 5-13. Summary of Proposed BACT (Continued, Page 2 of 3)

Emission Unit	Pollutant	Averaging Period	BACT Emission Limit	Compliance Method
Emergency diesel engines	NO _x	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
	SO ₂	N/A	ULSD fuel oil	Fuel oil supplier certifications
	CO	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
	VOC (as CH ₄)	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
	H ₂ SO ₄ Mist	N/A	ULSD fuel oil	Fuel oil supplier certifications
	HF	N/A	ULSD fuel oil	Fuel oil supplier certifications
	PM/PM ₁₀	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
Cooling tower	PM/PM ₁₀	N/A	Drift eliminators Drift Loss Rate of 0.0005 %	Cooling tower manufacturer certification
Material handling sources				
Transfer points	PM/PM ₁₀	N/A	Enclosure, partial enclosure, wet suppression, application of chemical wetting agents Baghouses/bin vents 5-percent opacity	Good operating practices EPA reference Method 9
Storage silos (dry materials)	PM/PM ₁₀	N/A	Baghouses/bin vents 5-percent opacity	EPA reference Method 9

Table 5-13. Summary of Proposed BACT (Continued, Page 3 of 3)

Emission Unit	Pollutant	Averaging Period	BACT Emission Limit	Compliance Method
Storage piles	PM/PM ₁₀	N/A	Wet suppression, application of chemical wetting agents, application of surface crusting agents	Good operating practices
Plant roads	PM/PM ₁₀	N/A	Paving of primary roadways, watering and/or sweeping	Good operating practices

*6 a.m. to 6 a.m.

Source: ECT, 2007.

6.0 AIR QUALITY IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

As previously noted in Section 3.1, TEC is located in an area that is designated attainment or unclassifiable for all criteria pollutants. All areas of Florida, with the exception of four PSD Class I areas, are designated as PSD Class II areas. The Florida PSD Class I areas include the Everglades National Park and the Chassahowitzka, St. Marks, and Bradwell Bay National Wilderness Areas. Accordingly, the TEC Site and vicinity are classified as a PSD Class II area. This section focuses on the methodology used to determine project air quality impacts with respect to the PSD Class II increments and the NAAQS. TEC air quality impacts with respect to the PSD Class I areas are addressed in Section 10.0.

The approach to assessing air quality impacts for a new or modified emission source generally begins by determining the impacts of only the proposed facility. If the impacts of the facility are below specified PSD SILs, then no further analysis is required. The PSD Class II SILs were previously presented in Table 3-4. If the impacts of a proposed facility are found to exceed a particular PSD SIL, further analysis considering other existing sources and background pollutant concentrations is required for that SIL.

The approach used to analyze the potential impacts of TEC, as described in detail in the following subsections, was developed in accordance with accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed. In addition, the ambient air impact analysis methodology used was consistent with previous methodologies approved by FDEP for similar type PSD projects.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, TEC will have the potential to emit 1,653 tpy of NO_x, 4,925 tpy of CO, 820 tpy of PM₁₀, 1,310 tpy of SO₂, 119 tpy of VOCs, and 131 tpy of H₂SO₄ mist. Table 3-2 previously provided estimated potential annual emission rates for TEC. As shown in that table, potential emissions of NO_x, CO, PM₁₀, SO₂, ozone/VOC, total fluorides, and H₂SO₄ mist are each pro-

jected to exceed the applicable PSD significant emission rate (SER) threshold. Potential emissions from TEC are below the applicable PSD SER levels for all other PSD regulated pollutants. Accordingly, TEC is subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C., for NO_x, CO, PM₁₀, SO₂, ozone/VOC, total fluorides, and H₂SO₄ mist.

6.3 MODEL SELECTION AND USE

Emissions and stack parameters for the main boiler were calculated for each of the five fuel types assuming 8,760 hr/yr of operation on each fuel type. Since the maximum hourly heat input varies based on fuel type, the emission rates will also vary between fuel types. The highest emission rate for each pollutant and each averaging period was selected for modeling. Worst-case stack parameters, based on all five fuel types, were used for modeling all pollutants and averaging periods. Since three of the four stack parameters—stack height, exit diameter, and exit temperature—are constant regardless of the fuel type, using the lowest exit velocity resulted in the worst-case stack parameters.

The most recent version of the American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD) modeling system (dated 07026), together with 5 years of pre-processed hourly meteorological data obtained from FDEP were used in the ambient impact analysis. AERMOD was used to obtain impact predictions for both short-term averaging periods (i.e., periods equal to or less than 24 hours) and annual averaging periods.

Regulatory agency-recommended procedures for conducting air quality impact assessments are contained in EPA's GAQM. The GAQM is codified in Appendix W of 40 CFR 51. In the November 9, 2005, Federal Register, EPA approved use of AERMOD as a GAQM Appendix A-preferred model effective December 9, 2005. AERMOD is recommended for use in a wide range of regulatory applications, including both simple and complex terrain. The AERMOD modeling system consists of meteorological and terrain preprocessing programs (AERMET and AERMAP, respectively) and the AERMOD dispersion model.

6.4 MODEL OPTIONS

Procedures applicable to the AERMOD modeling system specified in the latest version of the User's Guide for the AMS/EPA Regulatory Model – AERMOD (September 2004) and EPA's November 9, 2005, revisions to the GAQM were followed. In particular, the AERMOD control pathway MODELOPT keyword parameters DFAULT and CONC were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC option specifies the calculation of concentrations. TEC will be located in rural Taylor County. Accordingly, AERMOD options regarding pertinent to urban areas including increased surface heating (URBANOPT keyword) and pollutant exponential decay (HALFLIFE and DCAYCOEF keywords) were not employed. In addition, the option to use flagpole receptors (FLAGPOLE keyword) was not selected.

As previously mentioned, the AERMOD modeling system was used to determine annual average impact predictions, in addition to short-term averages, by using the PERIOD parameter for the AVERTIME keyword.

6.5 NO₂ AMBIENT IMPACT ANALYSIS

For annual NO₂ impacts, the tiered screening approach described in the GAQM, Section 6.2.3, was used. Tier 1 of this screening procedure assumes complete conversion of NO_x to NO₂. Tier 2 applies an empirically derived NO₂/NO_x ratio of 0.75 to the Tier 1 results.

6.6 TERRAIN CONSIDERATION

The GAQM defines *flat* terrain as terrain equal to the elevation of the stack base, *simple* terrain as terrain lower than the height of the stack top, and *complex* terrain as terrain exceeding the height of the stack being modeled.

Site elevation for TEC is approximately 65 feet above mean sea level (ft-msl). The TEC main stack height will be 550 ft above grade elevation. Accordingly, terrain elevations above approximately 615 ft-msl would be classified as complex terrain. U.S. Geological Survey (USGS) 7.5-minute series topographic maps were examined for terrain features in

the TEC impact area. Based on this examination, terrain in the vicinity of the Site is classified as simple terrain.

In accordance with the GAQM recommendations for AERMOD, each modeled receptor was assigned a terrain elevation based on USGS 7.5-minute digital elevation model (DEM) data and use of the AERMAP (Version 06341) preprocessing program. AERMAP was used in accordance with the latest version (December 2005) of the user's guide for the AERMOD terrain preprocessor (AERMAP) and EPA's November 9, 2005, revisions to the GAQM. AERMAP prepares terrain data for use by AERMOD in simple and complex terrain situations. This allows AERMOD to account for terrain using a simplification of the procedure used in the CTDMPLUS model.

6.7 BUILDING WAKE EFFECTS

The CAA Amendments of 1990 require the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds good engineering practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (40 CFR 51). GEP stack height is defined as the highest of 65 meters, or a height established by applying the formula:

$$H_g = H + 1.5 L$$

where: H_g = GEP stack height.

H = height of the structure or nearby structure.

L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While GEP stack height regulations require that stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The height proposed for the TEC main stack, 550 ft above grade level, will not be greater than the calculated GEP height of 167.6 meters (550 ft). Since the stack height of the TEC Project main stack is equal to the calculated GEP stack height, this stack height was used in the modeling analyses.

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. AERMOD evaluates the effects of building downwash based on the plume rise model enhancements (PRIME) building downwash algorithms. For the TEC ambient impact analysis, the complex downwash analysis implemented by AERMOD was performed using the current version of EPA's Building Profile Input Program (BPIP) for PRIME (BPIP-PRM) (Version 04274; September 30, 2004). The EPA BPIP program was used to determine the area of influence for each building/structure, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. BPIP output consists of an array of 36 direction-specific (10 to 360-degree [°]) building heights (BUILDHGT keyword), lengths (BUILDLIN keyword), widths (BUILDWID keyword), and along-flow (XBADJ keyword) and across-flow (YBADJ keyword) distances for each stack suitable for use as input to AERMOD. Dimensions of the building/structures evaluated for the wake effects were determined from engineering layouts and specifications and are shown in Table 6-1. The buildings are shown in three-dimension in Figure 6-1.

6.8 RECEPTOR GRIDS

Receptors were placed at locations considered to be ambient air, which is defined as "that portion of the atmosphere, external to buildings, to which the general public has access."

Since the entire perimeter of the TEC Property is not fenced, the nearest locations of general public access are at the facility fenceline. Therefore, receptors were placed along the fenceline and extended out using a Cartesian receptor grid.

Table 6-1. Dimensions of Major Buildings and Facilities

Building/Facility	Dimensions (ft)		
	North to South	East to West	Height
Turbine building	140	310	157
Boiler area	300	225	280
Air quality control system area	600	250	160*
Stack	80†	80†	550
Administration/warehouse building	475	125	60
Wastewater treatment building	75	250	30
Wastewater ponds (each)	250	250	Not applicable
Service building	350	125	60
Cooling tower (top of fan stack)	630	100	60
Rail car unloading building	150	50	30
Coal transfer house and tower	50	50	70
Coal inactive storage area	1,000	600	45
Petcoke inactive storage area	400	500	40
Coal stock-out pile	200†	200†	84
Petcoke stock-out pile	200†	200†	84
Coal and petcoke active storage shed	160	550	110
Crusher house	50	50	90
Coal pile runoff pond	500	500	Not applicable
Bottom ash byproduct storage area	460	365	80
FGD byproduct storage area	750	750	80
Fly ash byproduct storage area	575	575	80
Bottom ash byproduct runoff pond	350	350	Not applicable
FGD byproduct runoff pond	700	500	Not applicable
Fly ash byproduct runoff pond	600	550	Not applicable
Limestone truck unloading building	24	50	30
Limestone active storage pile	100†	100†	40
Limestone inactive storage pile	200	200	30
Limestone runoff pond	100	200	Not applicable
Reactant prep/gypsum product building	250	120	80
Gypsum stock-out building	120	200	60

*Maximum.

†Diameter.

Source: S&L, 2006.

6-7

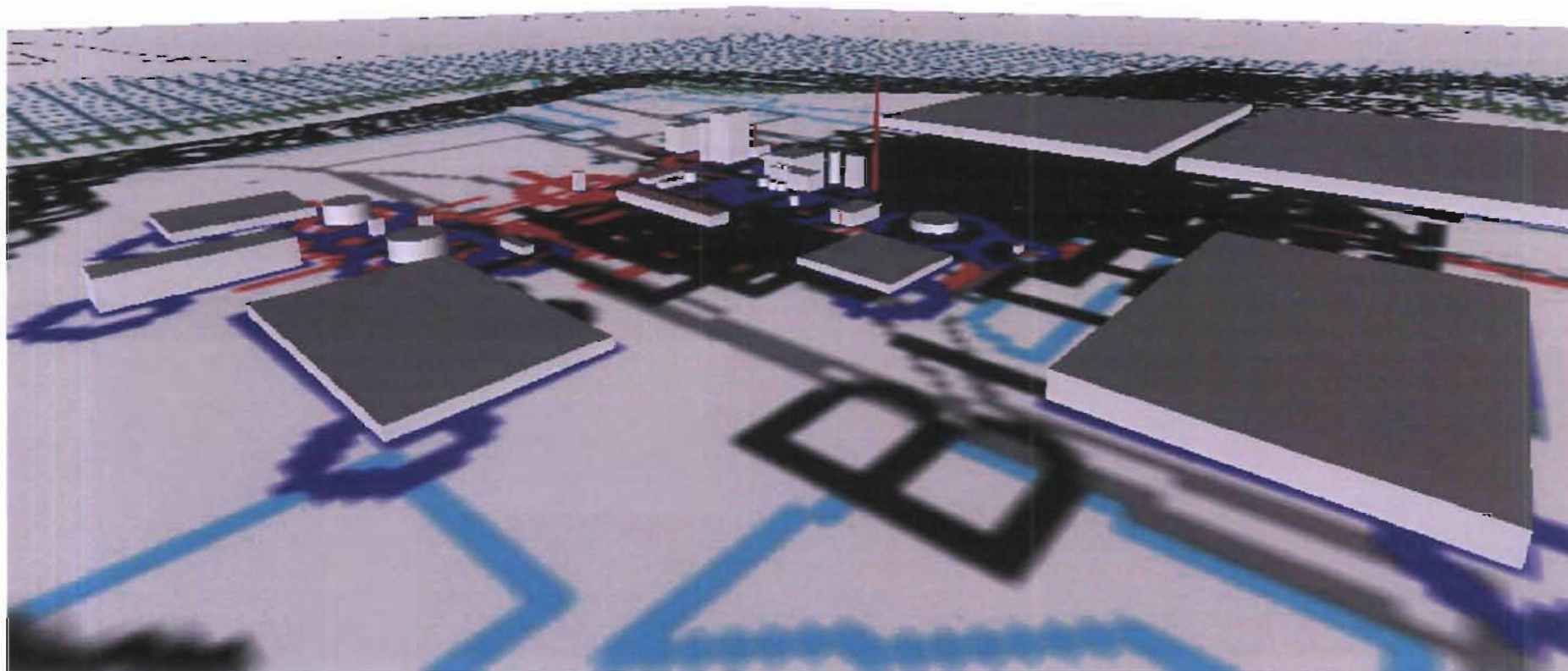


FIGURE 6-1.
BUILDINGS/STRUCTURES USED IN DOWNWASH ANALYSIS
VIEW LOOKING NORTHEAST

Source: ECT, 2007.



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The main objective of selecting a satisfactory receptor grid is to ensure the area of highest impact is located. To adequately locate the area of highest impact, the receptor grid must extend geographically beyond the highest impact receptor, and the receptor grid must have acceptable receptor spacing. FDEP usually recommends a receptor spacing of 100 meters around the point of highest impact.

Consistent with GAQM and FDEP recommendations, the ambient impact analysis used the following receptor grids:

- Fenceline receptors—Receptors placed along the entire site fenceline at 50-meter spacing.

SO₂, NO_x and CO Ambient Impact Analyses

- Tiered Cartesian Receptor Grid—Receptors, centered on the main stack and extending out from the fenceline to 3 km at 100-meter spacing and from 3 to 6 km at 250-meter spacing.

PM₁₀ Ambient Impact Analysis

- Cartesian Receptor Grid—Receptors, centered on the main stack and extending out from the fenceline to 3 km at 200-meter spacing were initially used to determine the maximum distance to significant impact. The maximum distance to significant impact was within this receptor grid for all years except for 2005. A receptor grid extending to 4 km was then used to determine distance to the significant impact for 2005.
- A second modeling grid was conducted using a smaller, tighter, 400-meter grid with 100-meter receptor spacing, centered on the maximum impact receptor.

Figure 6-2 illustrates a graphical representation of the fence line receptors. Figure 6-3 illustrates a graphical representation of the receptor grid used in the SO₂, NO_x, and CO ambient impact analyses. Figure 6-4 provides a graphical representation of the receptor grid used in the PM₁₀ ambient impact analysis.

6-9

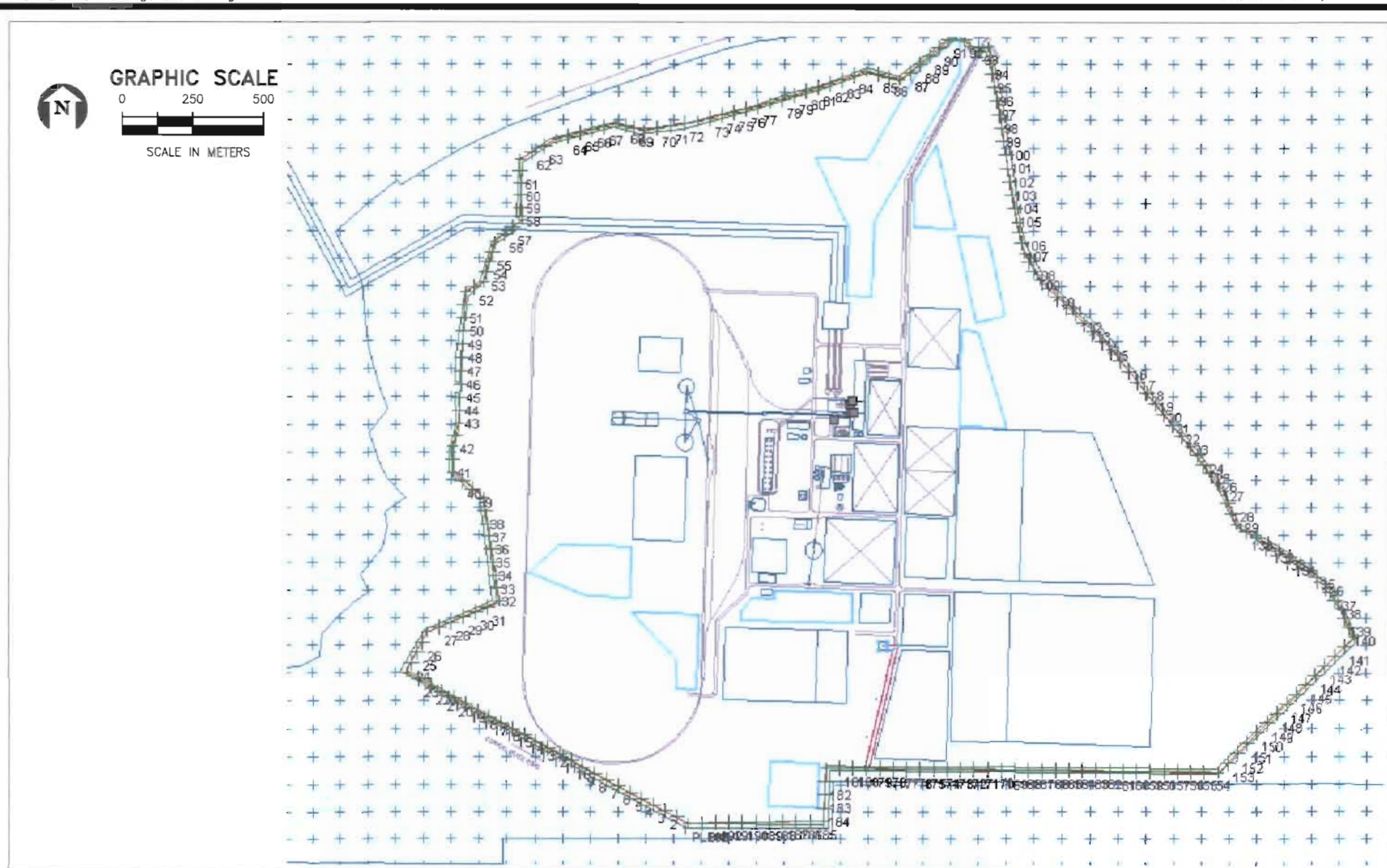
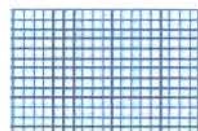
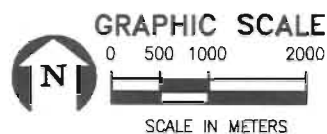


FIGURE 6-2.
TEC FENCELINE RECEPTORS

Source: ECT, 2007.



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100-METER SPACING
TO 3KM



200-METER SPACING
TO 6KM

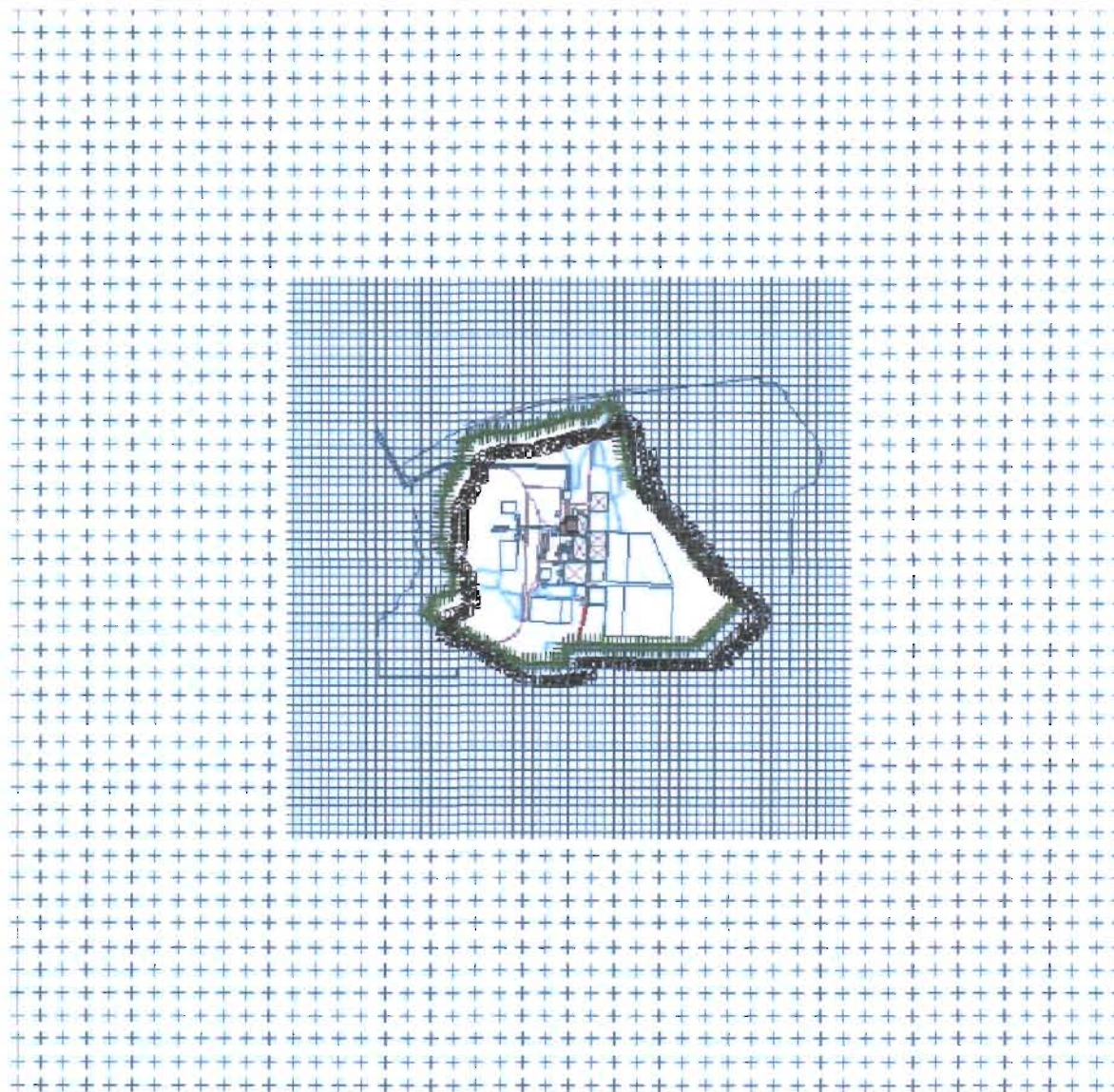


FIGURE 6-3.
RECEPTOR GRID (SO₂ NO_x AND CO ANALYSIS)

Source: ECT, 2007.

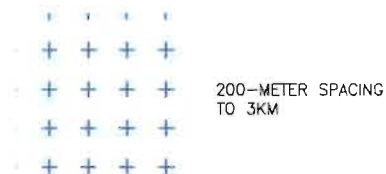
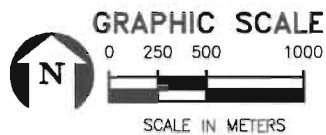


FIGURE 6-4.
RECEPTOR GRID (PM₁₀ ANALYSIS - 200-METER SPACING)

Source: ECT, 2007.



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The highest impact receptors for the SO₂, NO_x, and CO modeling analyses (with the exception of the 1-hour CO modeling analysis for 2003) were located within the 100-meter spaced grid. After the highest impact receptor was identified for the PM₁₀ analyses, a smaller receptor grid, 100-meter spacing centered on the highest impact receptor, was used to confirm the highest impact. Figure 6-5 illustrates a graphical representation of this 100-meter spaced receptor grid used in the PM₁₀ ambient impact analysis only.

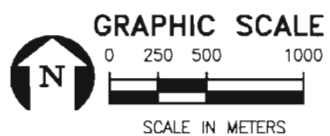
6.9 METEOROLOGICAL DATA

Meteorological data for use in the ambient air impact analysis was obtained directly from FDEP. This meteorological data was preprocessed using AERMET and contains both the surface data (.spf file extension) and the upper air or profile data (.pfl file extension) files for 5 consecutive years (2001 through 2005).

The meteorological data from Tallahassee Regional Airport was selected based on its close proximity to the TEC Site and its similar land use. The airport is located approximately 4 miles southwest of the city of Tallahassee. Both the airport and the TEC Project are located approximately the same distance inland from the Gulf Coast (i.e., 10 to 20 miles). To determine the appropriateness of using data from the airport location, the land use surrounding the airport was compared to what the land use would be at the TEC Site after it is built.

Recent aerial photographs were used to classify the land use within 3 km of the airport and the TEC Site. The TEC Site will include structures, buildings, roads, and unpaved storage areas. All of the area associated with the TEC Site was classified as urban, for which industrial use is a subclass. The results of the land use classification are as follows:

<u>Land Use Type</u>	<u>Tallahassee Airport</u>	<u>TEC</u>
Water	5 percent	—
Coniferous forest	65 percent	57 percent
Swamp	Approximately 1 percent	—
Cultivated land	Approximately 1 percent	—
Grassland	16 percent	23 percent
Urban	6 percent	20 percent
Low density residential	7 percent	—



+ + + + + 100-METER GRID
 + + + + + CENTERED ON
 + + + + + MAXIMUM IMPACT
 + + + + + RECEPTOR TO 400M

FIGURE 6-5.
RECEPTOR GRID (PM₁₀ ANALYSIS - 100-METER SPACING)

Source: ECT, 2007.



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The strongest similarity between the sites is the amount of forested land (i.e., 65 percent for the airport versus 57 percent for the TEC Project Site). The amount of grassland also compares favorably (i.e., 16 percent for the airport versus 20 percent for the TEC Project Site). These two predominant categories account for 81 percent of the land use at the airport and 80 percent of the land use at the TEC Project site. At each site, the urban type of development (i.e., the airport and the power plant) is the centrally located feature.

Since the land use is reasonably similar at the two sites, it can be concluded that the use of meteorology based on data collected at the Tallahassee Regional Airport is appropriate for modeling the impacts from the TEC Project.

6.10 MODELED EMISSION INVENTORY

6.10.1 ON-PROPERTY SOURCES

In addition to main boiler stack, the modeled emission sources for TEC will also include an auxiliary boiler; coal/petcoke/limestone receiving, storage, handling, and feed preparation; fly ash and gypsum storage and handling; various material handling transfer points; a 20-cell mechanical draft cooling tower; and paved roadways. Each of these TEC emission sources was addressed in the air quality impact analysis.

Appendix A provides summary tables of maximum short-term emission rates and stack parameters for each TEC emission source. Emission rates used for annual average impacts were annualized based on the projected worst-case annual operating mode for the TEC emission sources. All sources were assumed to operate for 8,760 hr/yr with the exception of the auxiliary boiler that was assumed to operate a maximum of 876 hr/yr (i.e., 10-percent capacity factor). (Note: Since one PM₁₀ modeling input file was used to determine impacts for both the 24-hour and annual averaging periods, the maximum hourly PM₁₀ emission rate for the auxiliary boiler was used. This emission rate was not annualized.) No scaling factors or variable emission rates were used in the ambient impact analysis.

6.10.2 OFF-PROPERTY SOURCES

The TEC maximum air quality impacts exceeded the PSD significant impact levels for PM₁₀ only (24-hour and annual averaging periods). Therefore, a full, multisource interactive assessment of NAAQS attainment and PSD Class II increment consumption was required for this pollutant and averaging periods.

The NAAQS inventory of off-property PM₁₀ sources within a 60-km radius of TEC was obtained from FDEP on December 6, 2006. It is generally accepted to include all off-property sources within a radius of 50 km from the maximum distance to any significant receptor. Since the maximum distance to significance is less than 10 km, including off-property sources within a 60-km radius is conservative. In addition, the entire NAAQS inventory was conservatively used for both the NAAQS analysis and the PSD increment analysis; all PM₁₀ sources were assumed to consume PSD increment. The off-property sources used in the NAAQS and PSD increment analyses are shown in Figure 6-6. Table 6-2 contains the complete inventory of offsite PM₁₀ sources, including the stack parameters and PM₁₀ emission rates.

Buckeye is located in close proximity to the TEC Site. The latest information for this facility was obtained from Golder Associates, Inc., on August 21, 2006. This information was used in lieu of that received from FDEP, because it was considered to be more up-to-date.

6.11 PROJECT IMPACTS AT PARTIAL LOADS

An ambient impact analysis is also required to assess impacts when the main boiler is operating under partial loads. The purpose of this analysis is to verify that the 100-percent main boiler load case results in the highest impact concentrations. Therefore, dispersion modeling was conducted for emissions from the main boiler for the following partial load cases: 30-, 50-, 75-, and 100-percent load. Emissions typically decrease as the main boiler load decreases resulting in lower impacts. However, exit velocity from the stack also decreases. The interaction of these two variables could potentially result in higher impacts at a reduced boiler load.

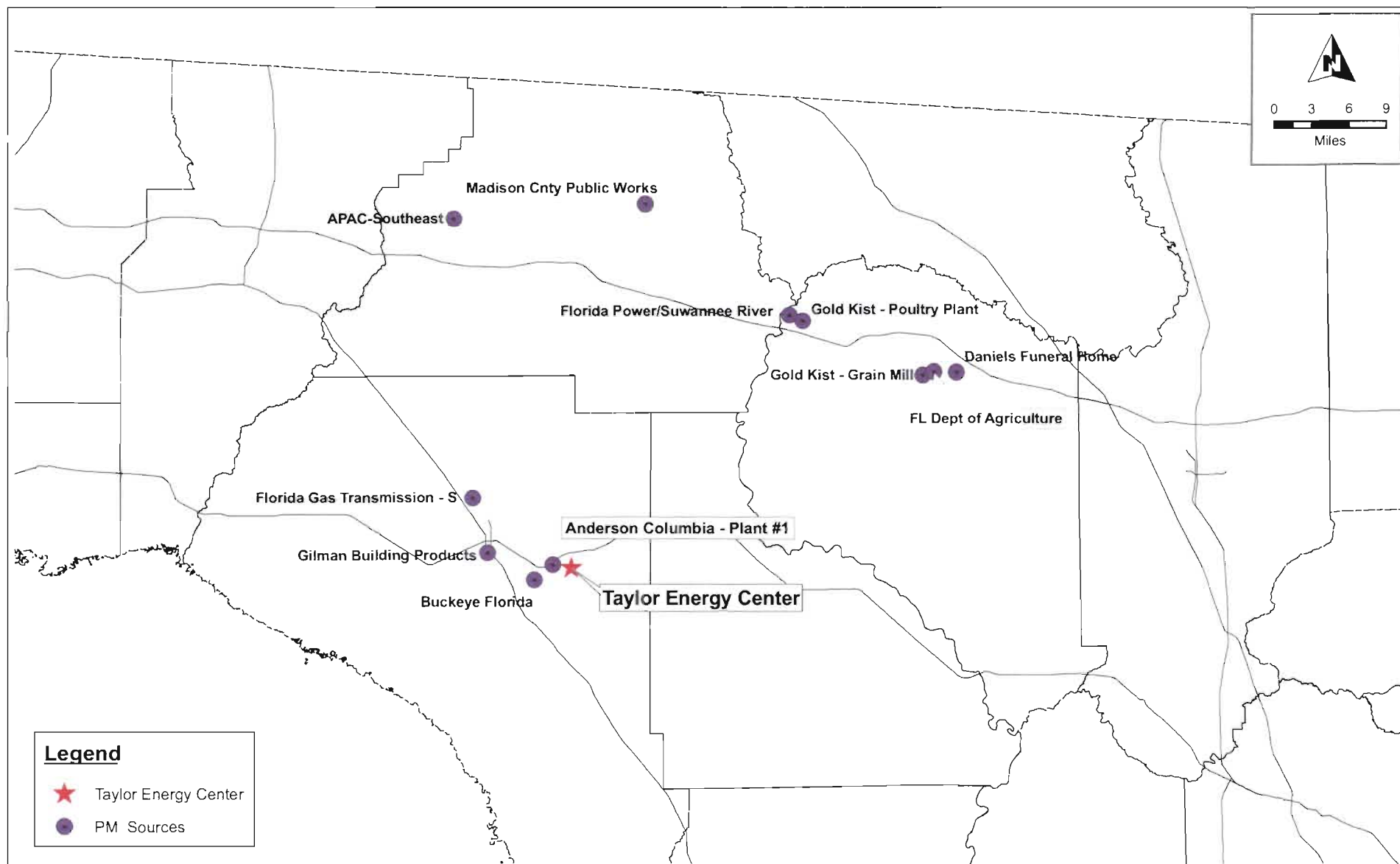


FIGURE 6-6.
OFF-PROPERTY PM₁₀ SOURCE LOCATIONS

Sources: FGDL, 2004; GA GIS Clearinghouse, 2004; ECT, 2007.



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Table 6-2. PM₁₀ Sources Within 60 Kilometers of the TEC Main Boiler Stack

Facility ID	Company Name/Site	EU Description	EU ID	Model ID	Zone 17 North UTM (km)	Zone 17 East UTM (km)	Base Elev (meter)	Emission Rate (g/s)	Stack Height (meter)	Exit Temp (K)	Stack Velocity (m/s)	Model Stack Diameter (meter)
1230001	Buckeye Florida, LP	#4 Lime Kiln	24	LK4	3328926.2	256814.4	16.0	1.61	38.10	511.00	15.20	2.23
1230001	Buckeye Florida, LP	#2 Recovery Boiler	6	RB2	3328859.8	256625.0	16.0	4.26	68.60	444.00	14.60	3.05
1230001	Buckeye Florida, LP	#3 Recovery Boiler	7	RB3	3328828.5	256546.4	16.0	4.14	68.60	450.00	13.60	2.90
1230001	Buckeye Florida, LP	#4 Recovery Boiler	11	RB4	3328816.4	256470.6	16.0	6.11	68.60	500.00	25.80	2.90
1230001	Buckeye Florida, LP	#2 Smelt Dissolving Tank	21	SDT2	3328895.3	256585.9	16.0	1.28	43.30	344.00	13.70	0.91
1230001	Buckeye Florida, LP	#3 Smelt Dissolving Tank	22	SDT3	3328841.2	256501.3	16.0	1.08	42.70	347.00	8.81	1.23
1230001	Buckeye Florida, LP	#4 Smelt Dissolving Tank	23	SDT4	3328822.7	256484.6	16.0	1.75	49.40	342.00	12.90	1.23
1230001	Buckeye Florida, LP	East & West Lime Bins		EWLB	3328991.3	256767.3	16.0	0.26	37.80	298.00	0.01	0.30
1230001	Buckeye Florida, LP	Nos 1 & 2 Lime Slakers		12LS	3328980.9	256778.6	16.0	0.26	40.50	334.00	1.16	0.59
1230001	Buckeye Florida, LP	Nos 1&2 Pwr boilers, Nos 1&2 bark boilers		COMBO	3328847.6	256564.2	16.0	29.50	68.60	367.00	19.00	3.96
0290004	Suwanee Lumber Co.	Lumber Dry Kiln #1	2	SLC2	292430.0	3279740.0	10.7	0.20	7.92	388.7	69.49	0.61
0290004	Suwanee Lumber Co.	Lumber Dry Kiln #2	3	SLC3	292430.0	3279740.0	10.7	0.25	10.00	388.7	0.01	1.00
0290004	Suwanee Lumber Co.	Direct Fired Kiln No.3	4	SLC4	292430.0	3279740.0	10.7	0.33	10.00	255.4	0.01	1.00
1210003	Florida Power/Suwannee River Plant	Boiler No. 1	1	SRP1	290500.0	3362200.0	21.3	17.39	33.53	432.0	18.90	2.13
1210003	Florida Power/Suwannee River Plant	Boiler No. 2	2	SRP2	290500.0	3362200.0	21.3	17.01	33.53	444.3	25.91	2.13
1210003	Florida Power/Suwannee River Plant	Boiler No. 3	3	SRP3	290500.0	3362200.0	21.3	17.39	41.15	422.0	33.22	2.35
1210003	Florida Power/Suwannee River Plant	CTEG Peaking Units No. 1, 2, 3	4,5,6	SRP4-6	290500.0	3362200.0	21.3	14.37	6.71	658.7	63.61	3.44
1210007	Gold Kist Inc. Grain Mill	#1 pellet system(strg.mill,cooling)	5	GKGM	307500.0	3354000.0	30.5	2.22	10.00	255.4	0.01	1.00
1210018	Gold Kist Poultry Plant - Live Oak	#3 Boiler, 800 HP, Process Steam	3,5,7	GKPP	292200.0	3361400.0	21.3	0.06	9.14	487.0	16.46	1.83
1210019	FL Dept of Agriculture/Live Oak Div.	Animal Crematory <=500 lb/hr)	1	FLDA	308880.0	3354380.0	32.3	0.05	6.10	1144.3	4.79	0.46
1210466	Daniels Funeral Home	Human Crematory	1	DFH	311760.0	3354240.0	42.7	0.04	10.00	255.4	0.01	1.00
1230033	Gilman Building Products	Wood Fired Boiler	1	GBP1	250700.0	3332500.0	12.2	1.16	13.72	492.0	4.69	0.97
1230033	Gilman Building Products	Board planning mill shavings collection sys	3	GBP3	250700.0	3332500.0	12.2	1.33	25.60	299.8	6.71	1.92
1230034	Florida Gas Transmission/Station 15	7222 bhp gas turbine compressor engine	4	FGT4	249000.0	3339600.0	15.2	0.06	18.59	787.6	0.01	2.19
1230034	Florida Gas Transmission/Station 15	15,000 bhp gas turbine compressor engine	6	FGT6	249000.0	3339600.0	15.2	0.10	18.29	760.9	21.76	2.30
7770017	Anderson Columbia, Inc./ Plant #10	#10 Asphalt Batch Plant W/BH	1	ACI	259050.0	3330780.0	18.3	1.45	7.01	408.2	25.91	1.16
7774805	APAC-Southeast/First Coast Div.	Relocatable Drum Mix Asphalt Plant	1	APAC	247490.0	3375690.0	30.5	1.51	10.67	427.6	24.78	1.19
7775321	Madison Cnty Public Works Dept/ Rocky Ford and West Farm Burn Sites	air curtain incinerator	1	MCPW	272170.0	3376960.0	39.6	0.70	10.00	255.4	0.01	1.00

Source: ECT, 2007.

An ambient impact analysis was performed using emissions and stack parameters from the main stack only at the four different loads. This analysis was performed for all 5 years of meteorological data using a nominal emission rate of 10 grams per second (g/s). The worst-case stack parameters (i.e., lowest exit velocity) for each load case were used based on the five different fuel types. The receptor grid used previously for the SO₂, NO_x, and CO analysis was also used for the partial load impact analysis.

Results of this ambient impact analysis were then adjusted based on the maximum actual emission rates for each pollutant, averaging period, and fuel type. Table 6-3 provides a summary of the maximum emission rates and minimum exit velocity used in the ambient impact analysis.

Table 6-3 Maximum Emission Rates and Worst-Case Stack Parameters for Partial Load Operations

		100-Percent Load		75-Percent Load		50-Percent Load		30-Percent Load	
<u>Maximum Emission Rates</u>									
Pollutant		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
NO _x		373.8	47.1	295.4	37.2	206.3	26.0	132.3	16.7
SO ₂ (annual)		299.0	37.7	236.3	29.8	165.0	20.8	105.8	13.3
SO ₂ (24-hour average)		411.2	51.8	324.9	40.9	226.9	28.6	145.5	18.3
SO ₂ (3-hour average)		523.3	65.9	413.5	52.1	288.8	36.4	185.2	23.3
CO		1,121.4	141.3	886.1	111.6	618.8	78.0	396.6	50.0
PM ₁₀ (total)		183.0	23.1	144.8	18.2	101.2	12.8	64.8	8.2
<u>Worst-Case Stack Parameters</u>									
Stack height	ft	550		550		550		550	
	meter	167.6		167.6		167.6		167.6	
Exit temperature	°F	130		130		130		130	
	K	327.6		327.6		327.6		327.6	
Exit velocity	fps	51.5		40.7		28.4		18.2	
	m/s	15.7		12.4		8.7		5.5	
Stack exit diameter	ft	30.8		30.8		30.8		30.8	
	meter	9.4		9.4		9.4		9.4	

Source: ECT, 2007.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 OVERVIEW

Comprehensive dispersion modeling was conducted to assess the air quality impacts resulting from TEC operations in accordance with the methodology described in Section 6.0. This section provides the results of the air quality assessment with respect to nearfield impacts. TEC air quality impacts at the distant PSD Class I areas resulting from long-range transport are addressed in Section 10.0.

Three separate sets of AERMOD input files were created for the SO₂ ambient impact analysis since each of the three applicable averaging periods (3-hour, 24-hour, and annual) had a different emission rate from the main boiler. One set of AERMOD input files were created for NO_x ambient impact analysis (since there is only one applicable averaging period) and CO (since the same emission rate is used for both 1- and 8-hour averaging periods). Each set of AERMOD input files consists of five separate input files, one for each year of meteorological data.

The PM₁₀ ambient impact analysis used five AERMOD input files, one for each year of meteorological data. Since both 24-hour and annual averaging periods were calculated from this one AERMOD input file, the maximum hourly PM₁₀ emission rates from the auxiliary boiler were used. Emissions from the auxiliary boiler were not annualized for the PM₁₀ ambient impact analysis. In addition, all off-property PM₁₀ sources were included. The following source groups were used: TEC (all TEC sources), BUCKEYE (all Buckeye Florida Foley Mill sources), OSS (all other off-site sources excluding Buckeye) and ALL (all sources.) The first high concentration from the TEC source group only was used for the PSD SIL analysis. The second high concentration from the ALL source group was used for comparison with the PSD Class II increment and the AAQS analysis.

7.2 RESULTS

7.2.1 PSD SIGNIFICANT IMPACT LEVEL ANALYSIS RESULTS

Comprehensive dispersion modeling using the EPA AERMOD dispersion model demonstrates that operation of TEC will result in ambient air quality impacts that exceed the

PSD Class II significant impact levels for 24-hour and annual PM₁₀ only (Tables 7-1 and 7-2). This result is further discussed in Section 7.2.2. All other modeled pollutants, SO₂, NO_x, and CO, are below the respective PSD Class II SILs for all averaging periods and therefore no further analysis is required (Tables 7-3 through 7-8).

Isopleths were developed for each pollutant and each averaging period for the year in which the highest impact occurred. These isopleths graphically show lines of equal predicted impacts from TEC operations and are provided as Figures 7-1 through 7-8.

7.2.2 PSD CLASS II INCREMENT ANALYSIS RESULTS

Since 24-hour and annual PM₁₀ impacts from TEC operations exceed the SILs, a multi-source interactive analysis of air quality impacts with respect to the 24-hour and annual PM₁₀ AAQS and PSD Class II increments was required. The maximum distance to significance for PM₁₀, based on the 24-hour and annual averaging periods for all 5 years, was determined to be 3.3 km. Therefore, this analysis must include all offsite sources of PM₁₀ emission within a radius of 53.3 km (i.e., maximum distance to significance plus 50 km). An inventory of offsite PM₁₀ sources within 60 km was used for the subsequent NAAQS and PSD Class II increment analyses.

The maximum second high concentration for the ALL source group was used in the PSD Class II increment analysis. As shown in Tables 7-9 and 7-10, the impacts from this analysis are below the 24-hour and annual PSD Class II increments, respectively.

Note that since the ambient air impact analysis used for comparison to the PSD SILs and determining the maximum distance to significance used a 200-meter spaced receptor grid, a smaller, more refined receptor grid of 100-meter spacing was used and centered on the maximum second high concentration receptor. This ensures that the maximum second

Table 7-1. Maximum Impacts—24-Hour PM₁₀ PSD SIL Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact PM ₁₀	µg/m ³	16.5	14.5	14.	14.2	19.1 —
PSD SIL	µg/m ³	5	5	5	5	5
Percent of SIL	%	330.0	289.0	298.6	284.4	381.0
Maximum impact receptor location	x	261,543.0	261,591.7	261,543.0	261,689.1	261,591.7
	y	3,329,296.8	3,329,296.3	3,329,96.8	3,329,295.3	3,329,296.3
Distance to maximum impact	km	0.95	0.95	0.95	0.97	0.95
Direction to maximum impact	°	174	171	174	166	171
Maximum distance to significance	x	262,449.1	259,649.1	259,49.1	258,649.1	262,249.1
	y	3,327,638.3	3,328,438.3	3,328,638.3	3,330,638.3	3,327,038.3
Distance to significance	km	2.79	2.55	2.72	2.83	3.30
Direction to significance	°	159	225	234	278	166

Note: All maximum impacts for 24-hour PM₁₀ PSD SIL Analysis were located on TEC fenceline.

Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x – 261,449.1 meter; y – 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-2. Maximum Impacts—Annual PM₁₀ PSD SIL Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact PM ₁₀	µg/m ³	1.82	1.77	1.74	1.77	1.75
PSD SIL	µg/m ³	1	1	1	1	1
Percent of SIL	%	181.9	177.3	174.0	177.2	175.2
Maximum impact receptor location	x	261,948.7	261,948.7	260,081.9	261,948.7	261,948.7
	y	3,311,902.8	3,331,902.8	3,330,683.5	3,331,902.8	3,331,902.8
Distance to maximum impact	km	1.74	1.74	1.44	1.74	1.74
Direction to maximum impact	°	17	17	288	17	17
Maximum distance to significance	x	259,849.1	259,849.1	259,649.1	259,849.1	2618,95.9
	y	3,331,038.3	3,331,038.3	3,330,838.3	3,331,038.3	3,331,931.3
Distance to significance	km	1.79	1.79	1.90	1.79	1.75
Direction to significance	°	297	297	288	297	15

Note: Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-3. Maximum Impacts—3-Hour SO₂ PSD SIL Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact SO ₂	µg/m ³	13.4	14.7	14.3	14.2	13.8
PSD SIL	µg/m ³	25	25	25	25	25
Percent of SIL	%	53.9	59.0	57.2	56.9	55.3
Maximum impact receptor location	x	261,649.1	261,392.9	261,549.1	262,200.2	260,185.1
	y	3,329,138.3	3,329,201.3	3,329,238.3	3,331,029.3	3,330,132.0
Distance to maximum impact	km	1.12	1.04	1.00	1.09	1.27
Direction to maximum impact	°	170	183	174	44	265

Note: Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-4. Maximum Impacts—24-Hour SO₂ PSD SIL Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact SO ₂	µg/m ³	4.3	4.5	4.2	4.6	4.7
PSD SIL	µg/m ³	5	5	5	5	5
Percent of SIL	%	86.5	90.4	83.1	92.0	94.8
Maximum impact receptor location	x	261,835.1	262,749.1	261,583.6	259,649.1	262,467.9
	y	3,329,293.5	3,330,638.3	3,331,802.8	3,330,538.3	3,329,286.3
Distance to maximum impact	km	1.02	1.36	1.57	1.82	1.39
Direction to maximum impact	°	158	73	5	279	133

Note: Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-5. Maximum Impacts—Annual SO₂ PSD SIL Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact SO ₂	µg/m ³	0.41	0.44	0.50	0.44	0.40
PSD SIL	µg/m ³	1	1	1	1	1
Percent of SIL	%	41.2	44.5	49.9	44.1	39.7
Maximum impact receptor location	x	260,134.1	261,237.8	261,237.8	261,194.2	261,237.8
	y	3,329,861.0	3,331,714.3	3,331,714.3	3,331,700.0	3,331,714.3
Distance to maximum impact	km	1.37	1.49	1.49	1.48	1.49
Direction to maximum impact	°	254	352	352	350	352

Note: Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-6. Maximum Impacts—Annual NO₂ PSD SIL Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact NO _x	µg/m ³	0.55	0.59	0.67	0.59	0.53
NO ₂ /NO _x ratio	µg/m ³	0.75	0.75	0.75	0.75	0.75
Maximum impact NO ₂	µg/m ³	0.42	0.44	0.50	0.44	0.40
PSD SIL	µg/m ³	1	1	1	1	1
Percent of SIL	%	41.5	44.3	49.9	44.2	40.0
Maximum impact receptor location	x	260,220.6	261,237.8	261,237.8	261,150.9	261,237.8
	y	3,329,898.8	3,331,714.3	3,331,714.3	3,331,689.3	3,331,714.3
Distance to maximum impact	km	1.27	1.49	1.49	1.48	1.49
Direction to maximum impact	°	255	352	352	348	352

Note: Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-7. Maximum Impacts—1-Hour CO PSD SIL Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact CO	$\mu\text{g}/\text{m}^3$	37.0	49.7	49.0	36.2	36.5
PSD SIL	$\mu\text{g}/\text{m}^3$	2,000	2,000	2,000	2,000	2,000
Percent of SIL	%	1.8	2.5	2.4	1.8	1.8
Maximum impact receptor location	x	261,397.0	259,749.1	258,749.1	261,194.2	262,102.8
	y	3,329,298.5	3,327,838.3	3,328,338.3	3,329,100.5	3,331,194.3
Distance to maximum impact	km	0.94	2.94	3.30	1.17	1.16
Direction to maximum impact	°	183	215	235	193	34

Note: Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-8. Maximum Impacts—8-Hour CO PSD SIL Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact CO	µg/m ³	27.0	25.7	23.3	24.7	25.7
PSD SIL	µg/m ³	500	500	500	500	500
Percent of SIL	%	5.4	5.1	4.7	4.9	5.1
Maximum impact receptor location	x	261,883.8	261,242.8	262,013.6	262,648.2	262,467.9
	y	3,329,293.0	3,329,101.3	3,331,708.0	3,330,536.3	3,329,286.3
Distance to maximum impact	km	1.04	1.16	1.57	1.24	1.39
Direction to maximum impact	°	155	190	21	76	133

Note: Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

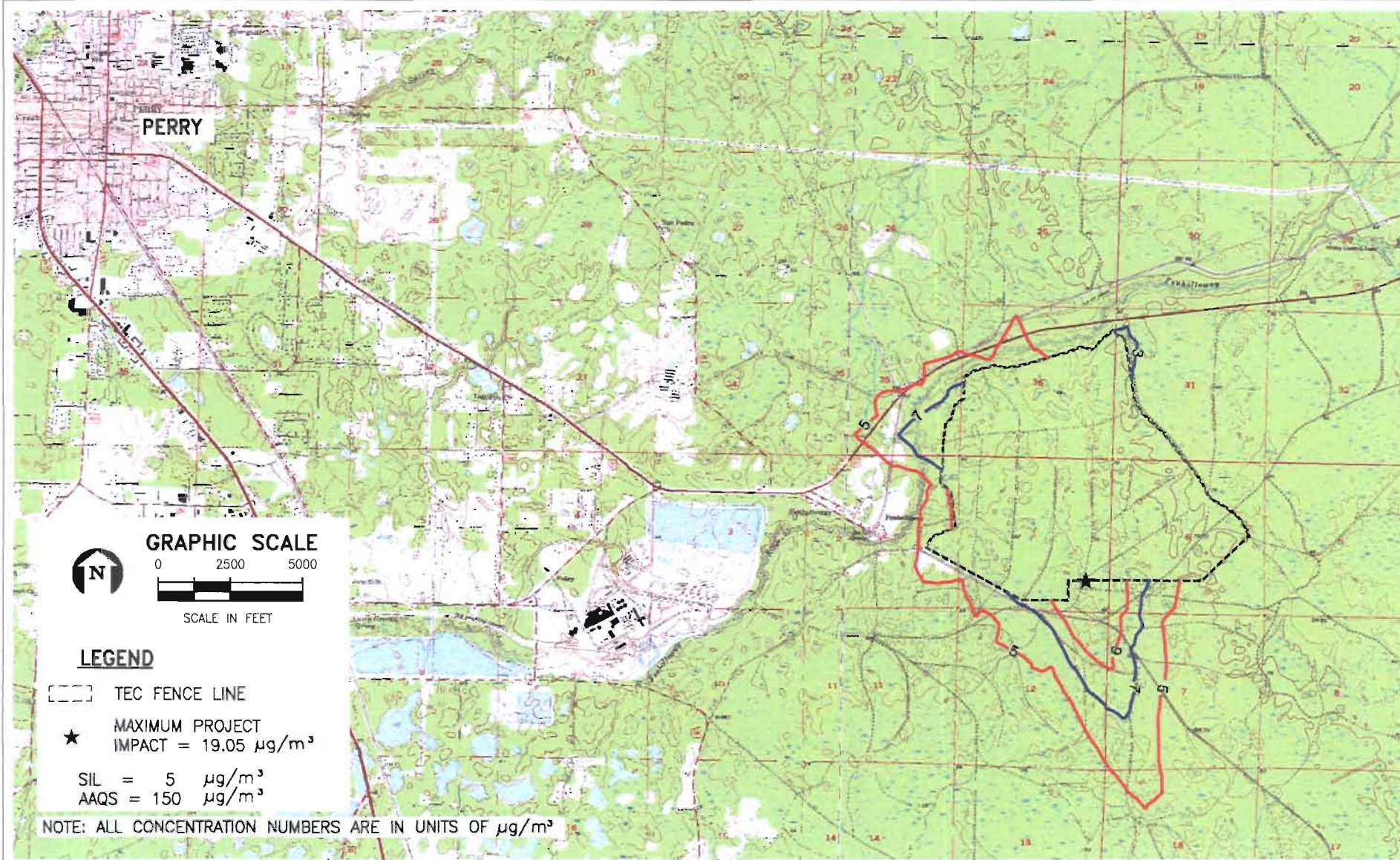


FIGURE 7-1.
24-HOUR PM_{10} IMPACTS FOR TEC - 2005

Source: USGS Quads: Boyd, Day NW, Perry, and Fenholloway, FL, 1993; ECT, 2007.



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7-12

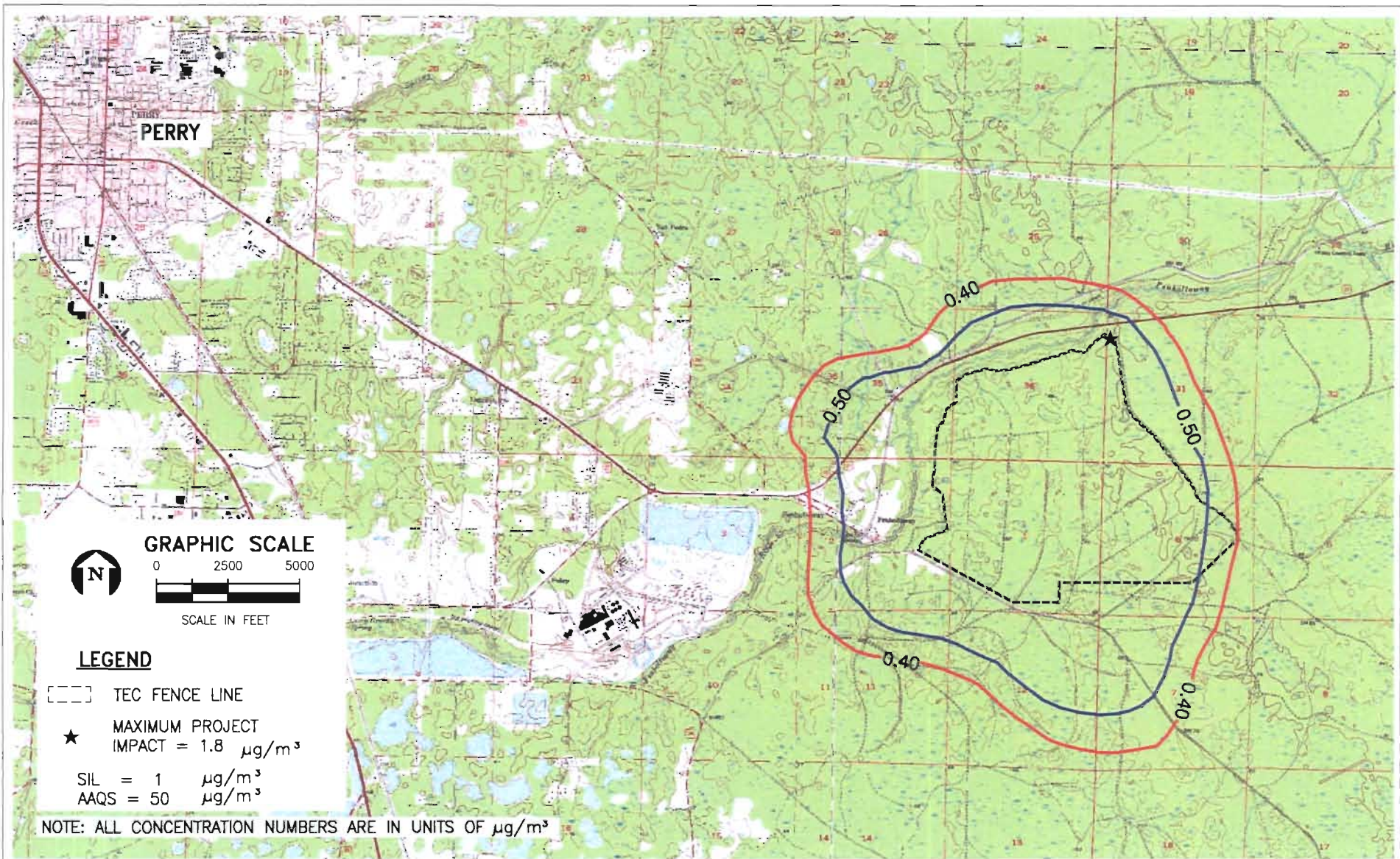


FIGURE 7-2.
ANNUAL PM_{10} IMPACTS FOR TEC - 2001

Source: USGS Quads: Boyd, Day NW, Perry, and Fenholloway, FL, 1993; ECT, 2007.

7-13

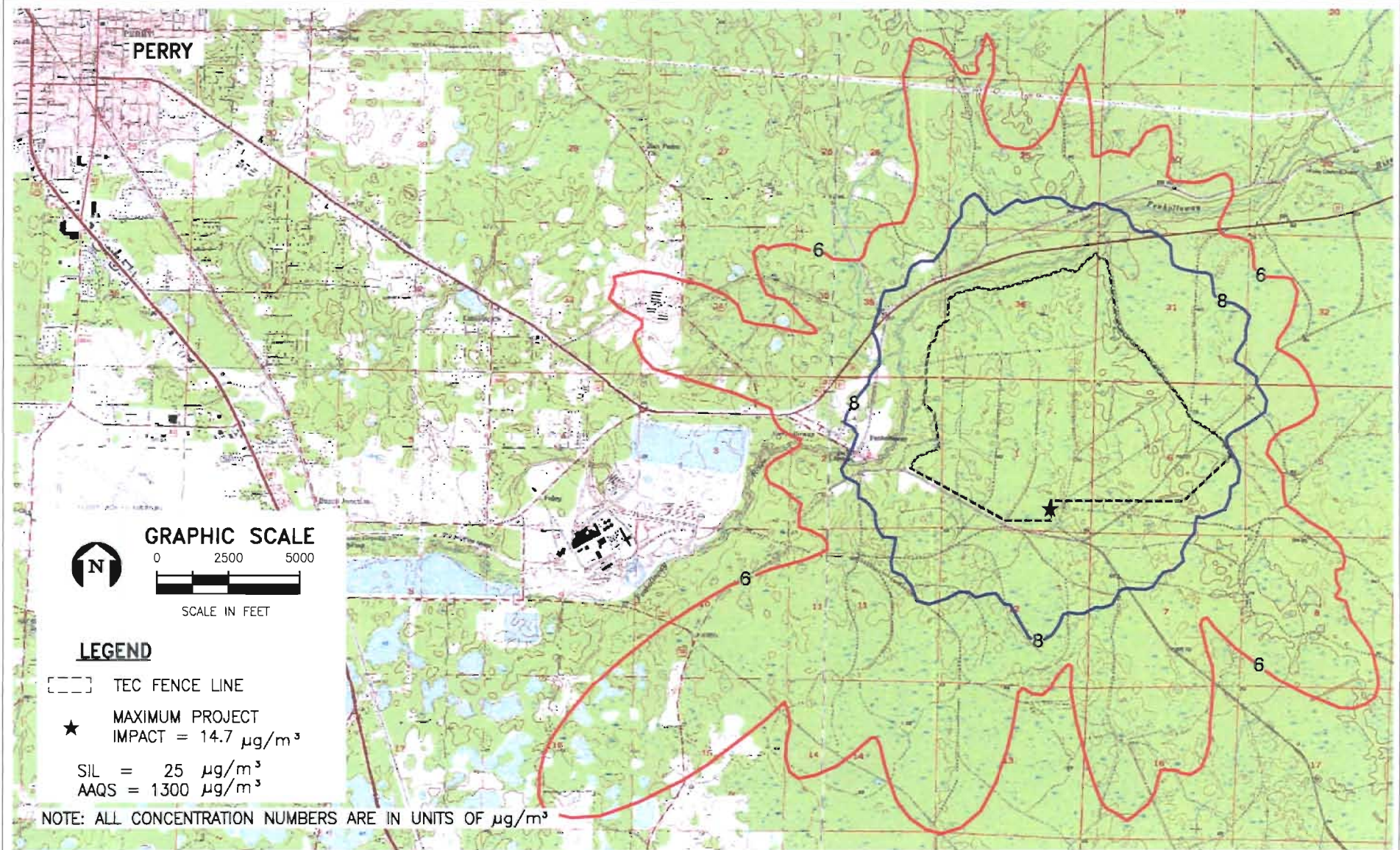


FIGURE 7-3.
3-HOUR SO_2 IMPACTS FOR TEC - 2002

Source: USGS Quads: Boyd, Day NW, Perry, and Fenholloway, FL, 1993; ECT, 2007.

7-14

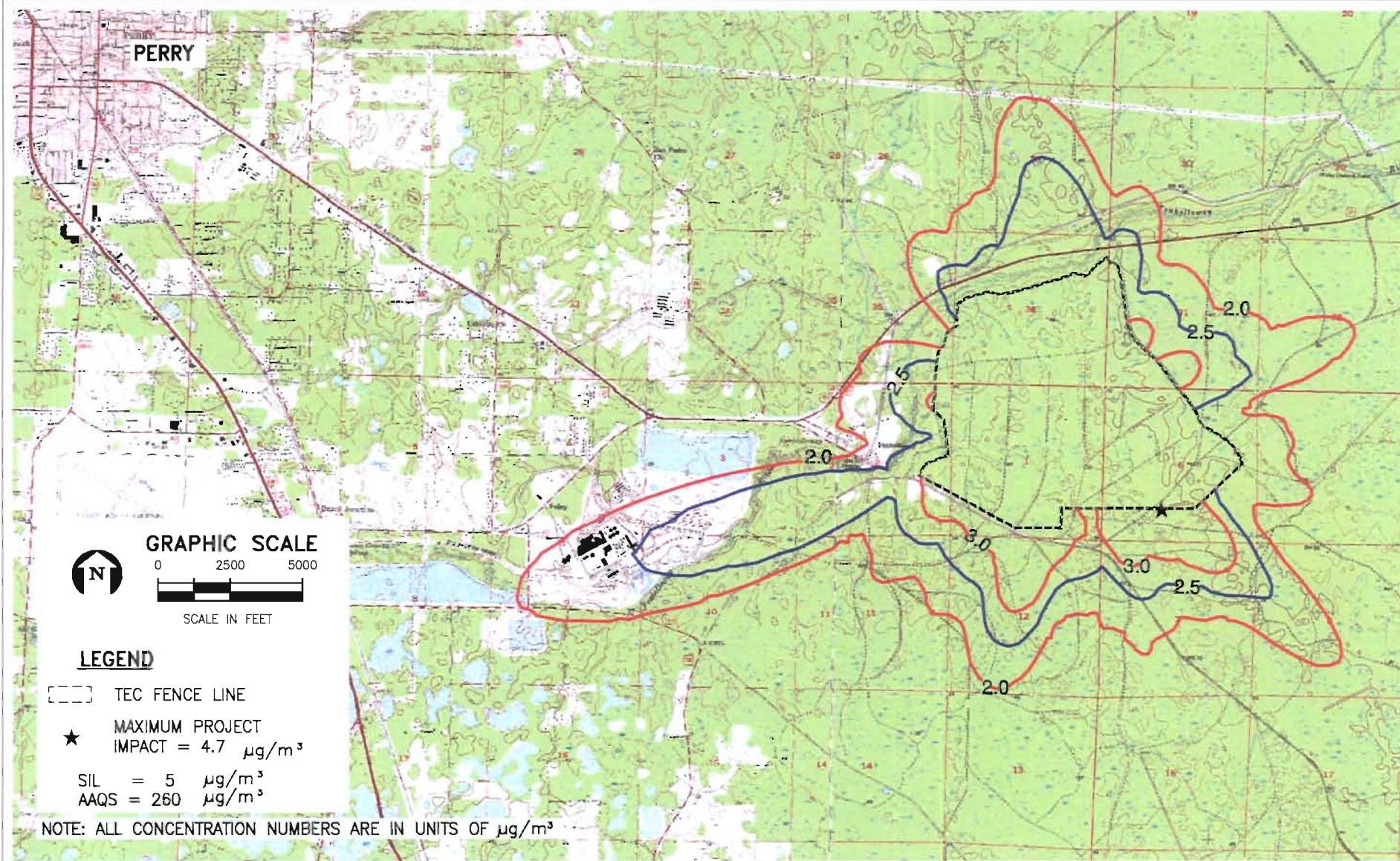


FIGURE 7-4.
24-HOUR SO_2 IMPACTS FOR TEC - 2005

Source: USGS Quads: Boyd, Day NW, Perry, and Fenholloway, FL, 1993; ECT, 2007.

7-15

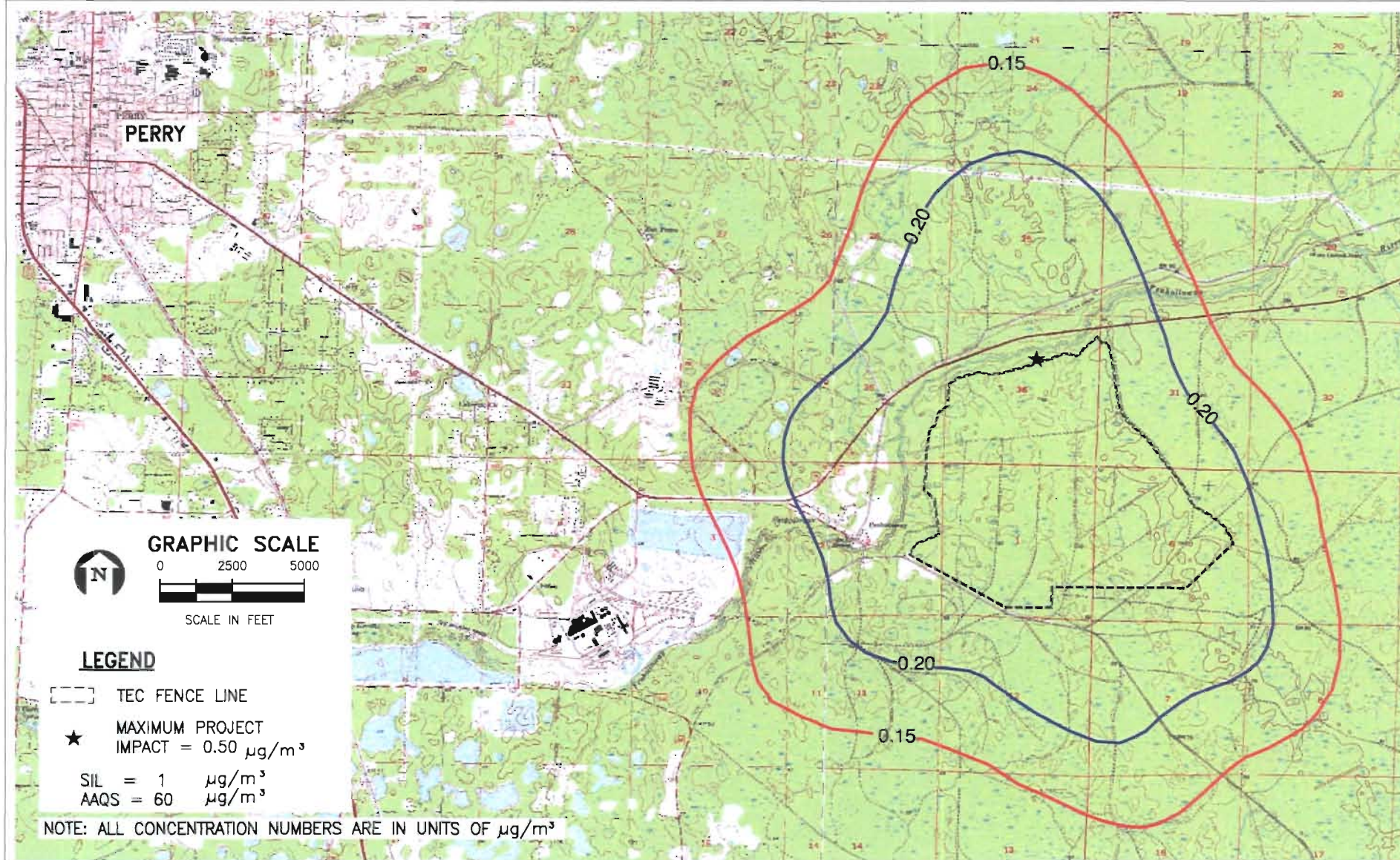


FIGURE 7-5.
ANNUAL SO_2 IMPACTS FOR TEC - 2003

Source: USGS Quads: Boyd, Day NW, Perry, and Fenholloway, FL, 1993; ECT, 2007.



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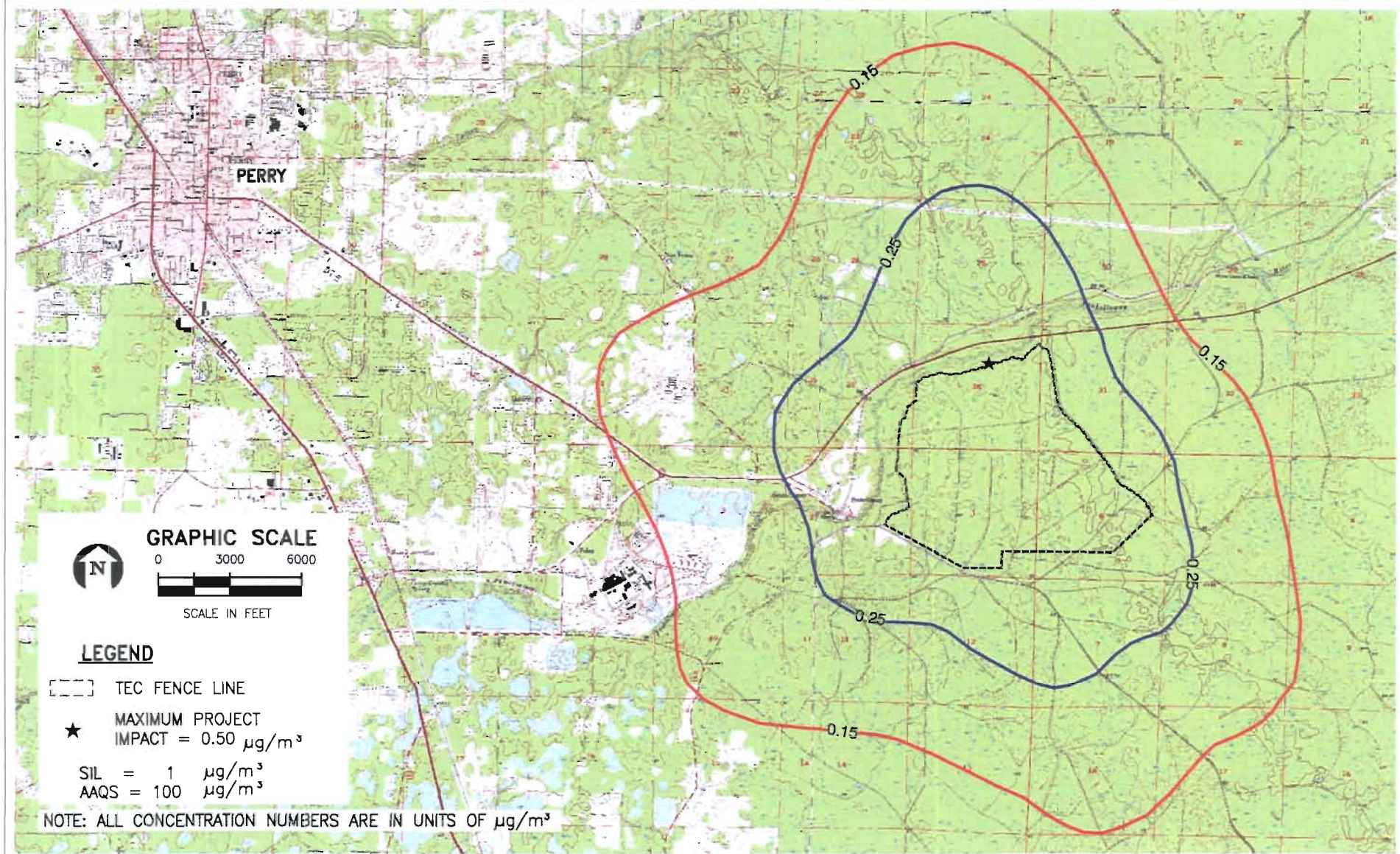


FIGURE 7-6.
ANNUAL NO₂ IMPACTS FOR TEC - 2003

Source: USGS Quads: Boyd, Day NW, Perry, and Fenholloway, FL, 1993; ECT, 2007.

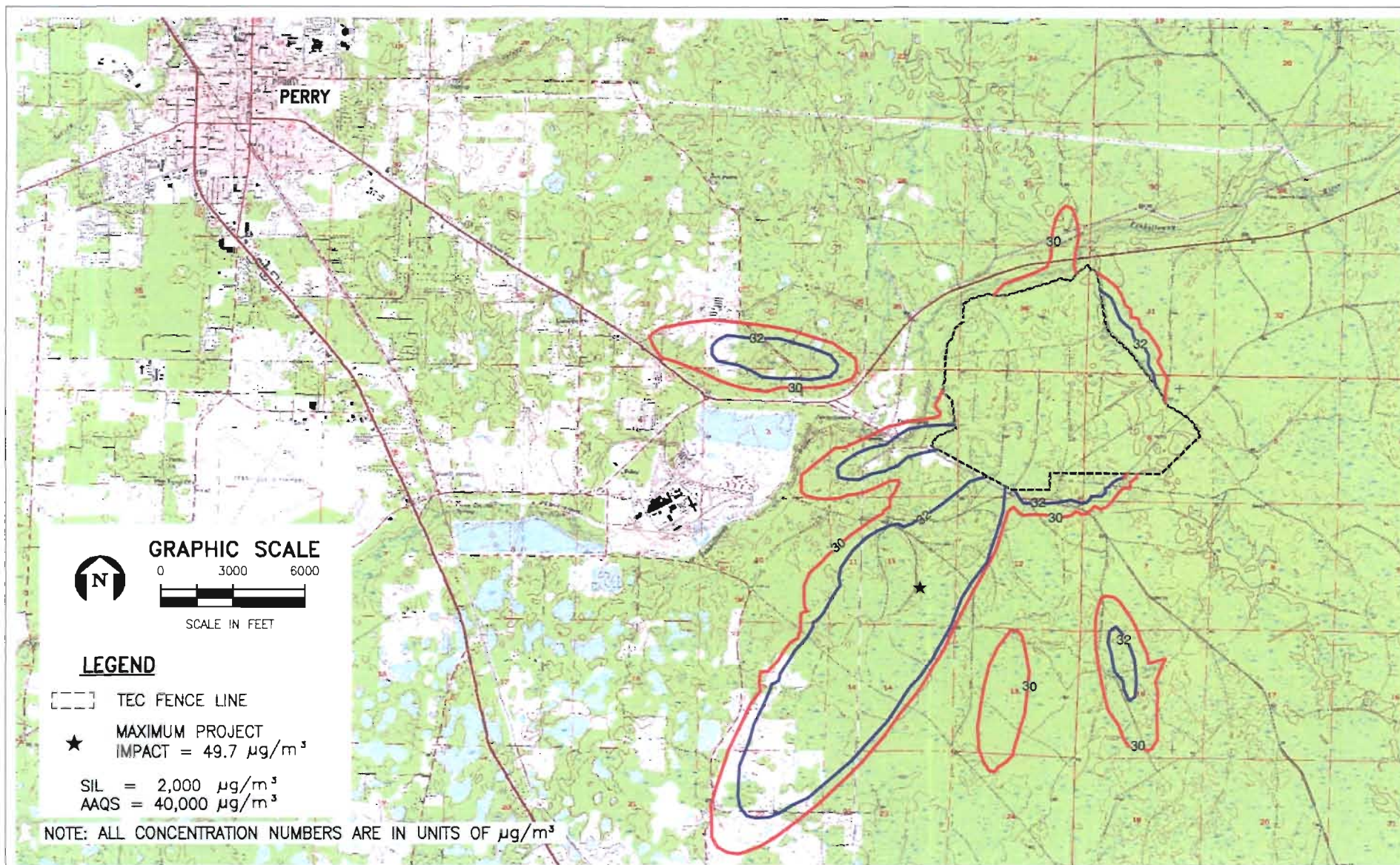


FIGURE 7-7.

1-HOUR CO IMPACTS FOR TEC - 2002

Source: USGS Quads: Boyd, Day NW, Perry, and Fenholloway, FL, 1993; ECT, 2007.

7-18

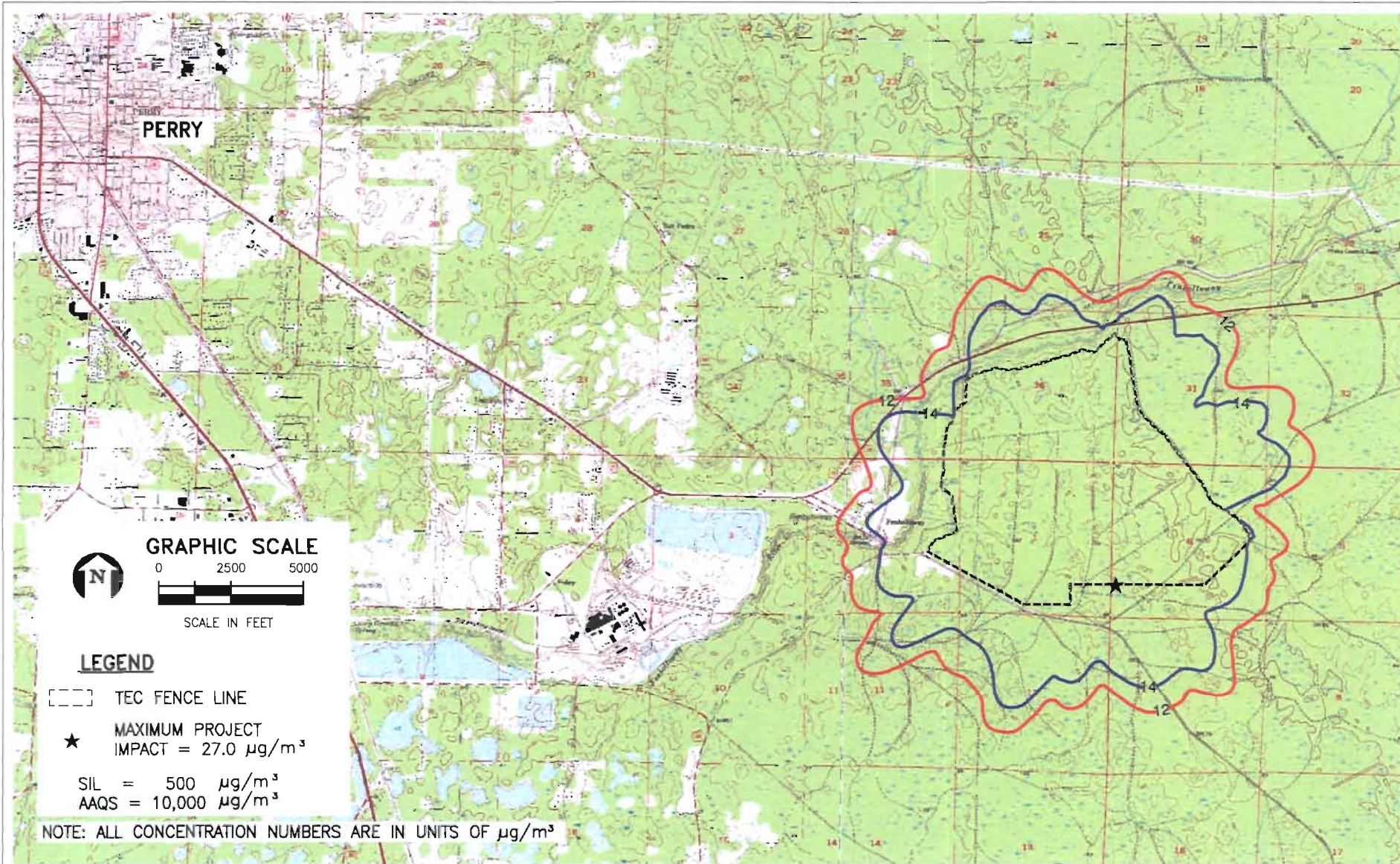


FIGURE 7-8.

8-HOUR CO IMPACTS FOR TEC - 2001

Source: USGS Quads: Boyd, Day NW, Perry, and Fenholloway, FL, 1993; ECT, 2007.



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Table 7-9. Maximum Impacts—24-Hour PM₁₀ PSD Increment Analysis Results

Year	Unit	2001	2002	2003	2004	2005
Maximum impact PM ₁₀	µg/m ³	24.9	28.1	24.2	23.9	28.4
PSD Class II increment	µg/m ³	30	30	30	30	30
Percent of PSD Class II increment	%	83.1	93.8	80.6	79.6	94.7
Maximum impact receptor location	x	259,149.1	259,149.1	259,149.1	258,949.1	259,049.1
	y	3,330,738.3	3,330,738.3	3,330,738.3	3,330,738.3	3,330,838.3
Distance to maximum impact	km	2.36	2.36	2.36	2.55	2.48
Direction to maximum impact	°	283	283	283	282	285

Note: Maximum impact based on second high concentration.

Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-10. Maximum Impacts—Annual PM₁₀ PSD Increment Analysis Results

Year	Unit	2001	2002	2003	2004	2005
Maximum impact PM ₁₀	µg/m ³	2.92	3.08	2.91	2.93	2.87
PSD Class II increment	µg/m ³	17	17	17	17	17
Percent of PSD Class II increment	%	17.2	18.1	17.1	17.2	16.9
Maximum impact receptor location	x	258,849.1	258,849.1	259,149.1	258,849.1	258,949.1
	y	3,330,738.3	3,330,738.3	3,330,638.3	3,330,738.3	3,330,738.3
Distance to maximum impact	km	2.65	2.65	2.34	2.65	2.55
Direction to maximum impact	°	282	282	281	282	282

Note: Maximum impact based on second high concentration.

Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

high impact concentration is obtained using the recommended 100-meter receptor spacing.

7.2.3 AMBIENT AIR QUALITY STANDARD (AAQS) ANALYSIS RESULTS

The maximum second high concentration for the ALL source group was used in the 24-hour average PM₁₀ AAQS analysis. To demonstrate compliance with the AAQS, a representative background air concentration must be added to the modeling result. For the 24-hour average, the highest ambient concentration of the second highest for the 5 most recent years of PM₁₀ ambient air concentration data was used. The ambient air concentrations for the 5 most recent years, 2002 through 2006, are shown in Table 8-1. A representative background PM₁₀ ambient concentration of 78 and 21 micrograms per cubic meter (µg/m³) was used for the 24-hour and annual averaging periods, respectively. As shown in Tables 7-11 and 7-12, the cumulative impacts from this analysis are below the 24-hour and annual AAQS, respectively.

7.2.4 AMBIENT IMPACT ANALYSIS FOR OPERATION AT PARTIAL LOADS

As shown in Table 7-13, results from the partial load ambient impact analysis indicate that maximum impacts from TEC operations occur when the main boiler is operating at 100-percent load. Therefore, the results and conclusions presented previously in this section for impacts compared to the PSD Class II SILs, PSD Class II increment levels, and NAAQS levels represent the maximum impacts from TEC operations at any boiler load.

7.3 OZONE IMPACTS

Ozone is formed in a complex series of chemical reactions involving primarily NO_x and VOCs during warm ambient temperatures in the presence of sunlight. Since ozone is formed from precursor pollutants, assessment of ambient ozone impacts is typically conducted on a regional basis using resource-intensive models such as the EPA Community Multiscale Air Quality (CMAQ) model. Currently, all areas of Florida are attaining the 8-hour ozone AAQS.

Table 7-11. Maximum Impacts—24-Hour PM₁₀ NAAQS Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact PM ₁₀	µg/m ³	24.9	28.1	24.2	23.9	28.4
Background concentration	µg/m ³	78.0	78.0	78.0	78.0	78.0
Total predicted concentration	µg/m ³	102.9	106.1	102.2	101.9	106.4
NAAQS	µg/m ³	150	150	150	150	150
Percent of NAAQS	%	68.6	70.8	68.1	67.9	70.9
Maximum impact receptor location	x	259,149.1	259,149.1	259,149.1	258,949.1	259,049.1
	y	3,330,738.3	3,330,738.3	3,330,738.3	3,330,738.3	3,330,838.3
Distance to maximum impact	km	2.36	2.36	2.36	2.55	2.48
Direction to maximum impact	°	283	283	283	282	285

Note: Maximum impact based on second high concentration.

Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-12. Maximum Impacts—Annual PM₁₀ NAAQS Analysis

Year	Unit	2001	2002	2003	2004	2005
Maximum impact PM ₁₀	µg/m ³	2.9	3.1	2.9	2.9	2.9
Background concentration	µg/m ³	21.0	21.0	21.0	21.0	21.0
Total predicted concentration	µg/m ³	23.9	24.1	23.9	23.9	23.9
NAAQS	µg/m ³	50	50	50	50	50
Percent of NAAQS	%	47.8%	48.2%	47.8%	47.9%	47.7%
Maximum impact receptor location	x					
	y	258,849.1	258,849.1	259,149.1	258,849.1	258,949.1
Distance to maximum impact	km	3,330,738.3	3,330,738.3	3,330,638.3	3,330,738.3	3,330,738.3
Direction to maximum impact	°	2.65	2.65	2.34	2.65	2.55
		282	282	281	282	282

Note: Maximum impact based on second high concentration.

Units of location coordinates (x, y) are in meters, Zone 17 UTM coordinates.

TEC main boiler stack coordinates are x = 261,449.1 meters; y = 3,330,238.3 meters.

Source: ECT, 2007.

Table 7-13. Ambient Impact Analysis Results for Operations at Partial Loads

	100-Percent Load					75-Percent Load					50-Percent Load					30-Percent Load				
	2001	2002	2003	2004	2005	2001	2002	2003	2004	2005	2001	2002	2003	2004	2005	2001	2002	2003	2004	2005
Nominal 10 g/s Impacts:																				
High, 1-Hour ($\mu\text{g}/\text{m}^3$)	2.51	3.39	3.35	2.44	2.40	2.84	3.69	3.64	2.75	2.72	3.30	4.14	4.09	3.26	3.32	4.17	4.70	4.63	4.10	4.19
High, 3-Hour ($\mu\text{g}/\text{m}^3$)	2.04	2.23	2.16	2.15	2.09	2.30	2.53	2.47	2.46	2.42	2.79	3.10	2.99	2.92	2.98	3.50	3.92	3.80	3.49	3.95
High, 8-Hour ($\mu\text{g}/\text{m}^3$)	1.83	1.72	1.45	1.64	1.73	2.09	1.94	1.66	1.87	1.96	2.49	2.33	2.13	2.23	2.30	3.11	2.91	2.82	2.73	2.79
High, 24-Hour ($\mu\text{g}/\text{m}^3$)	0.83	0.87	0.80	0.88	0.91	0.95	1.00	0.90	1.01	1.03	1.14	1.22	1.11	1.21	1.22	1.43	1.44	1.37	1.45	1.45
Annual ($\mu\text{g}/\text{m}^3$)	0.109	0.118	0.132	0.117	0.105	0.128	0.135	0.152	0.134	0.121	0.162	0.162	0.183	0.162	0.146	0.208	0.204	0.222	0.196	0.182
SO₂																				
Emission rate (g/s), 3-hour	65.90	65.90	65.90	65.90	65.90	52.10	52.10	52.10	52.10	52.10	36.40	36.40	36.40	36.40	36.40	23.30	23.30	23.30	23.30	23.30
Emission rate (g/s), 24-hour	51.80	51.80	51.80	51.80	51.80	40.90	40.90	40.90	40.90	40.90	28.60	28.60	28.60	28.60	28.60	18.30	18.30	18.30	18.30	18.30
Emission rate (g/s), annual	37.70	37.70	37.70	37.70	37.70	29.80	29.80	29.80	29.80	29.80	20.80	20.80	20.80	20.80	20.80	13.30	13.30	13.30	13.30	13.30
High, 3-hour ($\mu\text{g}/\text{m}^3$)	13.44	14.71	14.26	14.19	13.80	12.00	13.19	12.89	12.80	12.63	10.16	11.30	10.89	10.62	10.84	8.15	9.14	8.86	8.13	9.21
High, 24-hour ($\mu\text{g}/\text{m}^3$)	4.293	4.485	4.120	4.573	4.727	3.890	4.084	3.671	4.139	4.228	3.259	3.481	3.162	3.461	3.488	2.613	2.631	2.504	2.649	2.661
Annual ($\mu\text{g}/\text{m}^3$)	0.4117	0.4445	0.4985	0.4403	0.3969	0.3826	0.4013	0.4516	0.3992	0.3598	0.3370	0.3368	0.3802	0.3361	0.3029	0.2761	0.2709	0.2954	0.2611	0.2427
NO₂																				
Emission rate (g/s)	47.10	47.10	47.10	47.10	47.10	37.20	37.20	37.20	37.20	37.20	26.00	26.00	26.00	26.00	26.00	16.70	16.70	16.70	16.70	16.70
Tier 2 annual ($\mu\text{g}/\text{m}^3$)	0.3858	0.4165	0.4671	0.4126	0.3719	0.3582	0.3757	0.4228	0.3737	0.3369	0.3160	0.3157	0.3564	0.3151	0.2839	0.2600	0.2551	0.2782	0.2459	0.2285
PM₁₀																				
Emission rate (g/s)	23.10	23.10	23.10	23.10	23.10	18.20	18.20	18.20	18.20	18.20	12.80	12.80	12.80	12.80	12.80	8.20	8.20	8.20	8.20	8.20
High, 24-hour ($\mu\text{g}/\text{m}^3$)	1.914	2.000	1.837	2.039	2.108	1.731	1.817	1.634	1.842	1.881	1.459	1.558	1.415	1.549	1.561	1.171	1.179	1.122	1.187	1.192
Annual ($\mu\text{g}/\text{m}^3$)	0.2523	0.2723	0.3054	0.2698	0.2432	0.2337	0.2451	0.2758	0.2438	0.2197	0.2074	0.2073	0.2340	0.2068	0.1864	0.1702	0.1670	0.1821	0.1610	0.1496
CO																				
Emission rate (g/s)	141.30	141.30	141.30	141.30	141.30	111.60	111.60	111.60	111.60	111.60	78.00	78.00	78.00	78.00	78.00	50.00	50.00	50.00	50.00	50.00
High, 1-hour ($\mu\text{g}/\text{m}^3$)	35.49	47.92	47.30	34.49	33.97	31.65	41.18	40.59	30.65	30.40	25.76	32.28	31.89	25.42	25.87	20.83	23.52	23.17	20.49	20.94
High, 8-hour ($\mu\text{g}/\text{m}^3$)	25.87	24.29	20.50	23.18	24.49	23.38	21.70	18.52	20.89	21.90	19.46	18.14	16.62	17.43	17.91	15.55	14.53	14.11	13.63	13.95

Note: Maximum impacts for each pollutant and each averaging period are shown in bold.

Source: ECT, 2007.

TEC Project estimated potential NO_x and VOC emissions are 1,653 and 119 tpy, respectively. These annual emission rates are relatively minor in comparison to regional emissions. For example, Duval County (Jacksonville area) NO_x and VOC emissions in 2001 were 75,601 and 45,026 tons, respectively, based on data obtained from the EPA AirData Web site. NO_x and VOC emissions for Leon County (Tallahassee area) in 2001 were 9,981 and 12,574 tons, respectively. Alachua County (Gainesville area) NO_x and VOC emissions in 2001 were 14,053 and 14,035 tons, respectively. In contrast, rural Taylor County had NO_x and VOC emissions of 5,014 and 6,061 tons, respectively, in 2001. Duval, Leon, and Alachua Counties, all of which have higher population densities and greater NO_x and VOC emissions compared to Taylor County (including the emission increases associated with the TEC Project), currently have monitored ambient ozone levels below the ozone AAQS.

Ambient ozone levels in Taylor County are primarily due to ozone transport from upwind areas. Despite significant increases in population and motor vehicle activity, ambient ozone air quality in Florida has improved over the last 5 years due to improvements in motor vehicle emission rates. Continued reductions in average motor fleet emissions would be expected to further improve ozone air quality. In addition, the CAIR will result in significant actual reductions in existing power plant NO_x emissions throughout Florida. During Phase 1 (2009 through 2014) of the CAIR program, EPA estimates that actual Florida power plant NO_x emissions during the 5-month ozone season (May through September) will be reduced from 119,000 tons (in 2003) to 33,000 tons—a reduction of 86,000 tons. In comparison, TEC Project estimated ozone season NO_x emissions will be only approximately 700 tons. The CAIR program power plant emission reductions will occur throughout Florida, including areas in the vicinity of Taylor County, and will occur prior to the commencement of operation of the TEC Project. As an example, Gainesville Regional Utilities is retrofitting emission control systems to its existing Deerhaven Generating Station Unit 2 that will result in an estimated annual reduction in actual NO_x emissions of 3,200 tons—approximately twice the estimated TEC Project NO_x emissions.

In summary, the relatively minor NO_x and VOC emissions associated with the TEC Project will not significantly impact ambient ozone levels in Taylor County or other areas in

Florida. Taylor County is projected to remain in compliance with the ozone ambient quality standard due to the continued significant reductions in regional motor vehicle and power plant emissions.

7.4 AIR TOXICS MODELING RESULTS

7.4.1 INORGANIC

The release of inorganic substances termed HAPs is the result of metals and other inorganic constituents, such as fluorides and chlorides, which are found in natural, low concentrations in coal and/or petcoke and which may be volatilized during the process of combustion. The trace metals can then remain in the gas phase or can be condensed into solid phase PM. How much of this condensation occurs will be a function of the individual trace metal and temperature of the flue gases. The degree of condensation results from the volatilization properties of the individual metals and the flue gas temperature that exists prior to the particulate controls. For TEC, a combination of sequential emission controls including a baghouse (or fabric filter), wet FGD, and WESP will combine to limit emission of these substances to low levels.

Mercury is a naturally occurring trace element in the rocks and soil of Earth's crust. Small quantities of mercury occur in hydrocarbon fuels such as coal and oil. The concentration of mercury in coal varies with the location where it is mined but is typically within the range already found in Florida soils (i.e., from below detection limits up to 1 to 2 ppm). The mercury content of the solid fuels planned for the TEC main boiler is expected to range from 0.052 to 0.079 ppm. This small amount of mercury is released when coal or petcoke is burned, and it subsequently may be captured by specialized emissions control equipment, with a small amount being emitted to the atmosphere. The combination of emission controls planned for TEC is especially influential in the case of mercury. Mercury removal initially is enhanced by the SCR unit where mercury is oxidized into a form that is collected by the fabric filter, wet FGD, and WESP systems. Further, additives will be used to promote mercury removal. A mercury emission rate of 8.1×10^{-6} lb/MWh on an annual basis is proposed for TEC, a value which is approximately 60 percent less than EPA's recently issued mercury emissions limit of 20×10^{-6} lb/MWh for new sources

using bituminous coal, and is nearly 90 percent less than the corresponding EPA limit for plants using subbituminous coal (66×10^{-6} lb/MWh for wet units).

As another inorganic HAP example, lead emissions will be controlled efficiently by the fabric filter, which serves as the primary control device for PM. In addition, the inorganic HAP hydrogen fluoride (HF) will be removed readily in the wet FGD.

Radionuclides are often considered in emissions estimates. EPA has concluded that the risks from exposure to radionuclides from utilities are substantially lower than the risks from natural background radiation. Naturally occurring radionuclides from TEC will be well controlled as a result of the sequence of emission control devices. Emissions of naturally occurring radon in the coal fuel will not pose a health threat even to those who may live in close proximity to TEC. Uranium levels in fly ash from western coal are in the same range as the radionuclide levels in some types of natural rock formations and common building materials such as granite. In summary, TEC will not represent a threat to human health on the basis of radionuclides.

For the inorganic HAPs, the modeled maximum ground level air concentrations are well below state or federal health-based air quality criteria, ranging from at least 650,000 times less in the case of cobalt, to approximately four times less in the case of arsenic. Even these projections are quite conservative and are likely to overestimate the actual risks by a wide margin. In the special case of mercury, the modeled maximum ground level air concentration is 30 to 300 times less than the protective EPA reference air concentration (RfC).

For both inorganic and organic HAPs, the toxicological reference values principally were drawn from the EPA Integrated Risk Information System (IRIS), which represents a peer-reviewed compilation of protective doses and/or concentrations.

7.4.2 ORGANICS

In addition, organic HAPs can be produced during coal combustion, and emissions of these HAPs primarily are influenced by the specific features of facility boiler design and

operation, as described elsewhere in this SCA. TEC boilers will be designed and operated for high efficiency of combustion, which will dramatically limit the production of organic HAPs.

For the organic HAPs, the modeled maximum ground level air concentrations also are well below state or federal health-based air quality criteria, ranging from more than 370,000,000 times less in the case of ethyl chloride to approximately 110 times less in the case of acrolein. Even these projections are quite conservative and are likely to overestimate the actual risks by a wide margin.

7.4.3 ESTIMATES OF HAP EMISSIONS

Estimates of both organic and inorganic HAP emission rates were determined based on EPA AP-42 emission factors. In the case of metals, the AP-42 emission factors were used along with data available from the USGS COALQUAL database regarding typical coal constituent concentrations. The use of AP-42 emission factors for HAPs provides conservative estimates of actual emissions. The estimated HAP emissions for TEC were previously presented in Section 2.4, Tables 2-8, 2-9, and 2-10, as calculated from the AP-42 emission factors and conservative assumptions regarding fuel characteristics.

7.4.4 HAP RISK ASSESSMENT

An analysis was conducted to determine the ground level maximum air concentrations for all HAPs and compare these to published health-based exposure criteria or occupational exposure guidelines published for these substances. All of the substances except for dimethyl sulfate, hydrogen fluoride methyl hydrazine, and propionaldehyde, were compared to EPA health-based exposure criteria. Since dimethyl sulfate, hydrogen fluoride methyl hydrazine, and propionaldehyde do not have unrestricted health-based air guidelines, these were compared to occupational guidelines (i.e.: ACGIH Threshold Limit Value [TLV] or OSHA Permissible Exposure Limit [PEL]).

For the substances compared to EPA health-based exposure criteria, the standard acceptable benchmark value for cancer risk of 1×10^{-6} (i.e., one in one million) and the benchmark value for noncancer risks of 1.0 was used. Below these values, there is no signifi-

cant health risk. For all of these substances, the modeled maximum ground level concentrations are well below the health-based exposure criteria resulting in significant health risks. For the substances compared to the acceptable occupational exposure criteria (dimethyl sulfate, hydrogen fluoride methyl hydrazine, and propionaldehyde), the ground level air concentrations are between 41,000 and 200,000,000 times less than the published occupational exposure guidelines. This indicates a negligible risk from these substances.

Table 7-14 provides a summary of estimated cancer risks and hazard coefficients for the TEC HAPs.

7.4.5 HAP EMISSIONS IN THE CONTEXT OF OTHER MAJOR LOCAL FACILITIES

An issue has been raised during initial discussions on the TEC regarding how, or to what extent, TEC emissions of HAPs may compare to those released by an adjacent industrial facility, Buckeye. While comparisons cannot be made for every HAP, since the plants emit different substances, some conclusions can be drawn regarding those HAPs that are emitted by both facilities. Table 7-15 summarizes the 13 substances reported both on the EPA Toxic Release Inventory (TRI) list for Buckeye (considering years 2000 through 2004) and also on the HAPs list for TEC. The projected HAPs emissions from TEC for any individual chemical may be greater than, less than, or comparable to those reported by Buckeye. However, in all cases, the aggregate risks from the combined emissions for both sources will be well below applicable carcinogenic and noncarcinogenic health guidelines based on the estimated HAP emissions for both facilities (see also Table 7-14).

Table 7-14. HAP Risk Assessment for TEC

Chemical	Modeled Maximum Annual Average Concentration ($\mu\text{g}/\text{m}^3$)	U.S. EPA Exposure Guidelines		Calculated Cancer Risk (unitless)	Calculated Hazard Coefficient (unitless)
		Inhalation URF ($\mu\text{g}/\text{m}^3$)	Inhalation RfC ($\mu\text{g}/\text{m}^3$)		
Hydrogen fluoride	5.82E-03	NA	NA		
Antimony	3.55E-06	NA	1.40E-02		2.53E-04
Arsenic	6.89E-05	4.30E-03	NA	2.96E-07	
Beryllium	1.21E-05	2.40E-03	2.00E-02	2.90E-08	6.05E-04
Cadmium	2.10E-06	1.80E-03	NA	3.77E-09	
Chromium*	6.40E-02	NA	68.25		9.38E-04
Cobalt	2.63E-05	NA	17.5		1.50E-06
Lead	4.83E-05	NA	NA		3.22E-05
Manganese	3.74E-04	NA	5.00E-02		7.48E-03
Mercury	9.80E-04	NA	3.00E-01		3.27E-03
Nickel	4.63E-04	2.40E-04	NA	1.11E-07	
Selenium	3.57E-04	NA	16.975		2.10E-05
Vanadium	1.02E-03	NA	6.37E-01		1.60E-03
Radionuclides	†	NA	NA		
1,1,1-Trichloroethane	1.26E-05	NA	1001		1.25E-08
2,4-Dinitrotoluene	1.76E-07	NA	7		2.51E-08
2-Chloroacetophenone	4.40E-06	NA	3.00E-02		1.47E-04
Acetaldehyde	4.40E-06	2.20E-06	9	9.67E-12	4.89E-07
Acetophenone	9.42E-06	NA	350		2.69E-08
Acrolein	1.82E-04	NA	2.00E-02		9.11E-03
Benzene	8.16E-04	2.2-7.8E-06	30	6.37E-09	2.72E-05
Benzyl chloride	4.40E-04	4.85E-05	NA	2.13E-08	
Biphenyl	1.07E-06	NA	175		6.10E-09
Bis(2-ethylhexyl)phthalate (DEHP)	4.58E-05	NA	70		6.55E-07
Bromoform	2.45E-05	1.10E-06	NA	2.69E-11	
Carbon disulfide	8.16E-05	NA	700		1.17E-07
Chlorobenzene	1.38E-05	NA	59.5		2.32E-07
Chloroform	3.71E-05	2.30E-05	NA	8.52E-10	
Cumene	3.33E-06	NA	400		8.32E-09
Cyanide	1.57E-03	NA	70		2.24E-05
Dimethyl sulfate	3.01E-05	NA	NA		
Ethyl benzene	5.90E-05	NA	1000		5.90E-08
Ethyl chloride	2.64E-05	NA	10000		2.64E-09
Ethylene dibromide	7.54E-07	3.00E-04	8.995	2.26E-10	8.38E-08
Ethylene dichloride	2.51E-05	2.60E-05	105	6.53E-10	2.39E-07
Formaldehyde	1.51E-04	1.30E-05	NA	1.96E-09	
Hexane	4.21E-05	NA	700		6.01E-08
Hydrogen chloride (HCl)	5.62E-02	NA	20		2.81E-03
Isophorone	3.64E-04	NA	700		5.20E-07
Methyl bromide	1.00E-04	NA	50.05		2.01E-06
Methyl chloride	3.33E-04	NA	90		3.70E-06
Methyl ethyl ketone	2.45E-04	NA	5000		4.90E-08
Methyl hydrazine	1.07E-04	NA	NA		
Methyl methacrylate	1.26E-05	NA	700		1.79E-08
Methyl tert-butyl ether	2.20E-05	NA	3000		7.33E-09
Methylene chloride	1.82E-04	4.70E-07	NA	8.56E-11	
Naphthalene	8.16E-06	NA	3		2.72E-06
PAHs (as Benzo[a]pyrene)	1.20E-05	8.86E-04	NA	1.06E-08	
Phenol	1.00E-05	NA	1050		9.57E-09
Propionaldehyde	2.39E-04	NA	NA		
Styrene	1.57E-05	NA	1000		1.57E-08
Tetrachloroethylene	2.70E-05	NA	490		5.51E-08
Toluene	1.51E-04	NA	5000		3.01E-08
Total PCDD/PCDF (grams)	1.11E-09	33	NA	3.65E-08	
Vinyl acetate	4.77E-06	NA	200		2.39E-08
Xylenes	2.32E-05	NA	100		2.32E-07

Note: NA = not available.

The URF and RfC values are protective of potential carcinogenic effects and potential systemic effects, respectively.

Cancer risks calculated by multiplying the modeled concentration times the inhalation URF. Hazard Coefficients calculated by dividing the modeled concentration by the inhalation RfC.

The benchmark value for Cancer Risk is 1×10^{-6} (i.e., one in a million [$1.0\text{E-}06$]), below which there is no significant risk.

For systemic risks, the benchmark value (Hazard Coefficient) is 1, below which there is no significant health risk.

*Chromium emissions modeled as total chromium (ECT, 2007; pers. comm.). The majority of emitted chromium is in the form of Cr(III).

†Radionuclide emissions do not represent a significant health risk. See text for details.

Source: ECT, 2007.

Table 7-15. Comparison of HAP Emissions for TEC and Buckeye

Chemical	TRI Data—Buckeye (lb/yr to nearest lb)					Estimated TEC Emissions* (lb/yr to nearest lb)
	2004†	2003	2002	2001	2000	
Lead	228	216	226	155	NR	257
Manganese	360	350	360	3,700	3,900	1,969
Vanadium	NR	280	190	NR	NR	5,353
Acetaldehyde	146,000	135,000	120,000	57,000	60,000	25
Chloroform	40,300	38,600	38,200	27,900	27,900	195
Formaldehyde	17,300	16,300	17,300	18,000	18,000	874
Hydrogen chloride (HCl)	108,000	100,000	100,000	110,000	100,000	296,323
Methyl chloride	39,005	34,008	37,008	34,011	37,012	1,750
Methyl ethyl ketone	NR	18,500	18,100	13,000	13,000	1,288
Naphthalene	11,410	NR	NR	NR	NR	46
PAHs (as benzo[a]pyrene)	381	340	365	344	410	63
Phenol	8,000	8,000	8,400	5,800	6,100	53
Total PCDD/PCDF‡	1.49	1.39	1.44	1.38	0.98	2.64

Note: NR = not reported.

*Section 2.4 of the PSD; ECT, 2007.

†2004 is the most recent data available.

‡PCDD/PCDF values presented in grams year rather than lb/yr.

Source: Hazardous Substance & Waste Management Research, Inc., 2007.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest ambient air quality monitoring station is located on County Road 137 in Hamilton County, approximately 76 km northeast of TEC. This station monitors the ambient air for PM₁₀ and SO₂. The nearest ambient air quality monitoring station that monitors for 1- and 8-hour average ozone is located on Miccosukee Road Greenways Trail in Tallahassee, approximately 83 km northwest of the project site. The nearest NO₂ ambient air quality monitoring station is located on Bennett Street in Jacksonville, Duval County, approximately 180 km east of the project site. The nearest CO ambient air quality monitoring station is located on South McDuff Avenue in Jacksonville, approximately 172 km east of the project site. The nearest ambient air quality monitoring station for lead is situated in Tampa, Hillsborough County, approximately 150 km west of the Stanton Energy Center. The Hillsborough County site that monitors ambient air for lead is operated by the Hillsborough County Environmental Protection Commission (HCEPC). Table 8-1 provides summaries of the 2002 through 2006 ambient air quality data for these monitoring stations.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EX-EMPTION APPLICABILITY

As previously discussed in Section 3.2, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Because several PSD pollutants will be emitted from TEC in excess of their respective significant emission rates, preconstruction monitoring is required. However, Rule 62-212.400(2)(e), F.A.C., provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. The *de minimis* ambient impact levels were previously presented in Table 3-1. To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from TEC.

Table 8-1. Taylor County Area Ambient Air Quality Data—2002 through 2006

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration ($\mu\text{g}/\text{m}^3$)				Percent of Standard
	County	City								1 st High	2 nd High	Arithmetic Mean	Standard	
PM ₁₀	Hamilton	N/A	County Road 137	120470015	76	62	2002	24-hour		73	50		150†	48.7
							2003			50	44		150†	33.3
							2004			51	51		150†	34.0
							2005			120	78		150†	80.0
							2006			55	49		150†	36.7
							2002	Annual	7,967			17*	50‡	34.0
							2003		8,628			17	50‡	34.0
							2004		7,285			18*	50‡	36.0
							2005		8,582			20	50‡	40.0
							2006		5,728			21*	50‡	42.0
PM _{2.5}	Leon	Tallahassee	Tallahassee Community College	120730012	93	295	2002	24-hour		36	35		65†	55.4
							2003			41	29		65†	63.1
							2004			56	39		65†	86.2
							2005			56	44		65†	86.2
							2006			37	37		65/35†§§	56.9/105/7
							2002	Annual	117			12.9	15‡	86.0
							2003		3,978			12.5*	15‡	83.3
							2004		8,378			13.9	15‡	92.7
							2005		8,317			14.8	15‡	98.7
							2006		5,916			14.1*	15‡	94.0
		N/A	Route 16	120731005	82	292	2002	24-hour		N/A	N/A		65†	N/A
							2003			35	34		65†	53.9
							2004			54	50		65†	83.1
							2005			38	38		65†	58.5
							2006			35	34		65/35†§§	53.9/100.0
							2002	Annual	N/A			N/A	15‡	N/A
							2003		2,949			12.1*	15‡	80.7
							2004		7,945			12.9	15‡	86.0
							2005		7,608			12.4*	15‡	82.7
							2006		6,073			12.1*	15‡	80.7
SO ₂	Hamilton	N/A	County Road 137	120470015	76	62	2002	3-hour	8,671	73.4	70.7		1,300§	5.7
							2003		8,664	62.9	57.6		1,300§	4.8
							2004		8,634	68.1	68.1		1,300§	5.2
							2005		8,451	73.4	65.5		1,300§	5.7
							2006		6,216	28.8	28.8		1,300§	2.2
							2002	24-hour	8,671	26.2	23.6		365§	7.2
							2003		8,664	18.3	18.3		365§	5.0

Table 8-1. Taylor County Area Ambient Air Quality Data—2002 through 2006 (Continued, Page 2 of 4)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration ($\mu\text{g}/\text{m}^3$)				Percent of Standard
	County	City								1 st High	2 nd High	Arithmetic Mean	Standard	
SO ₂ (contd.)							2004	24-hour	8,634	28.8	23.6		365§	7.9
							2005		8,451	23.6	18.3		365§	6.5
							2006		6,216	15.7	10.5		365§	4.3
							2002	Annual	8,671			8.9	80‡	11.1
							2003		8,664			5.2	80‡	6.5
							2004		8,634			4.7	80‡	5.9
							2005		8,451			4.5	80‡	5.6
							2006		6,216			3.4	80‡	4.3
NO ₂	Duval	Jacksonville	Bennett Street	120310032	180	81	2002	Annual	7,944			28.9	100‡	28.9
							2003		7,041			28.3	100‡	28.3
							2004		7,451			27.1	100‡	27.1
							2005		7,890			26.3	100‡	26.3
							2006		5,964			22.8	100‡	22.8
CO	Duval	Jacksonville	Lasalle Street	120310080	177	84	2002	1-hour	7,931	3,200	2,972		40,000§	8.0
							2003		8,374	3,086	2,629		40,000§	7.7
							2004		8,167	3,315	3,086		40,000§	8.3
							2005		7,928	5,144	3,543		40,000§	12.9
							2006		6,085	8,687	8,687		40,000§	21.7
							2002	8-hour	7,931	2,515	2,286		10,000§	25.2
							2003		8,374	2,286	2,172		10,000§	22.9
							2004		8,167	2,286	1,829		10,000§	22.9
							2005		7,928	2,629	2,172		10,000§	26.3
							2006		6,085	1,600	1,486		10,000§	16.0
			South McDuff Avenue	120310083	172	82	2002	1-hour	7,971	5,715	4,458		40,000§	14.3
							2003		8,003	3,772	3,657		40,000§	9.4
							2004		7,963	4,343	3,543		40,000§	10.9
							2005		7,862	3,772	3,315		40,000§	9.4
							2006		6,378	3,886	3,886		40,000§	9.7
							2002	8-hour	7,971	3,200	2,743		10,000§	32.0
							2003		8,003	2,972	2,743		10,000§	29.7
							2004		7,963	2,972	2,629		10,000§	29.7
							2005		7,862	2,286	2,172		10,000§	22.9
							2006		6,378	2,629	1,829		10,000§	26.3

Table 8-1. Taylor County Area Ambient Air Quality Data—2002 through 2006 (Continued, Page 3 of 4)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration ($\mu\text{g}/\text{m}^3$)				
	County	City								1 st High	2 nd High	Arithmetic Mean	Standard	Percent of Standard
CO (contd.)			Rosselle and Copeland	120310084	172	83	2002	1-hour	8,398	4,686	3,886		40,000§	11.7
							2003		8,428	4,572	4,343		40,000§	11.3
							2004		8,123	4,115	3,886		40,000§	10.3
							2005		8,207	4,343	3,658		40,000§	10.9
							2006		6,334	4,229	4,115		40,000§	10.6
							2002	8-hour†‡	8,398	3,086	2,972		10,000§	30.9
							2003		8,428	3,429	2,743		10,000§	34.3
							2004		8,123	3,200	2,629		10,000§	32.0
							2005		8,207	3,429	2,515		10,000§	34.3
							2006		6,334	2,286	1,486		10,000§	22.9
Lead	Duval	Jacksonville	Bennett Street	120310032	180	81	2002	24-hour	40			0.01	1.5	0.7
							2003		N/A			N/A	1.5	N/A
							2004		N/A			N/A	1.5	N/A
							2005		N/A			N/A	1.5	N/A
							2006		N/A			N/A	1.5	N/A
			Rosselle and Copeland	120310084	172	83	2002	24-hour	41			0.01	1.5	0.7
							2003		N/A			N/A	1.5	N/A
							2004		N/A			N/A	1.5	N/A
							2005		N/A			N/A	1.5	N/A
							2006		N/A			N/A	1.5	N/A

Table 8-1. Taylor County Area Ambient Air Quality Data—2002 through 2006 (Continued, Page 4 of 4)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Years	Averaging Period	Number of Observations	Ambient Concentration (ppm)		
	County	City								3-Year Average of 4 th High	Standard	Percent of Standard
Ozone	Leon	Tallahassee	Tallahassee Community College	120730012	93	295	2000 through 2002 2001 through 2003 2002 through 2004 2003 through 2005 2004 through 2006	1-hour	N/A	0.083	0.12	69.2
									N/A	0.080	0.12	66.7
									N/A	0.078	0.12	65.0
									N/A	0.078	0.12	65.0
									N/A	0.078	0.12	65.0
							2000 through 2002 2001 through 2003 2002 through 2004 2003 through 2005 2004 through 2006	8-hour	N/A	N/A	0.08	N/A
									N/A	0.071	0.08	88.8
									N/A	0.070	0.08	87.5
									N/A	0.071	0.08	88.8
									N/A	0.070	0.08	87.5
			Miccosukee Road Greenways Trail	120730013	83	302	2000 through 2002 2001 through 2003 2002 through 2004 2003 through 2005 2004 through 2006	1-hour	N/A	0.078	0.12	65.0
									N/A	0.080	0.12	66.7
									N/A	0.080	0.12	66.7
									N/A	0.080	0.12	66.7
									N/A	0.080	0.12	66.7
							2000 through 2002 2001 through 2003 2002 through 2004 2003 through 2005 2004 through 2006	8-hour	N/A	N/A	0.08	N/A
									N/A	0.071	0.08	88.8
									N/A	0.071	0.08	88.8
									N/A	0.071	0.08	88.8
									N/A	0.071	0.08	88.8

*Does not satisfy summary criteria.

†98th percentile.

‡Arithmetic mean.

§2nd high.

**4th highest day with hourly value exceeding standard over a 3-year period.

††4th highest daily maximum 8-hour concentration over a 3-year period.

‡‡Monitor values represent 3rd and 4th highest 8-hour concentrations.

§§PM_{2.5} 24-hour standard of 35 µg/m³ became effective in October 2006.

Sources: FDEP, 2007.

EPA, 2007.

ECT, 2007.

The results of these analyses were presented in detail in Section 7.0. The following paragraphs summarize the dispersion modeling results as applied to the preconstruction ambient air quality monitoring exemptions.

8.2.1 PM₁₀

The maximum 24-hour PM₁₀ impact was predicted to be 19.05 µg/m³. This concentration is above the 10-µg/m³ *de minimis* level ambient impact level for PM₁₀, and therefore a preconstruction monitoring exemption in accordance with Rule 62-212.400(3)(e), F.A.C., is not applicable. However, in accordance with EPA guidance (EPA, 1992) representative current quality-assured ambient data collected at an FDEP ambient monitoring site in the general vicinity of TEC can be used to satisfy the PSD preconstruction ambient air monitoring requirements. The ambient air data collected by FDEP at Site 120470015, County Road 137 in Hamilton County, is representative ambient air data for PM₁₀, and therefore onsite preconstruction ambient air monitoring is not required.

8.2.2 SO₂

The maximum 24-hour SO₂ impact was predicted to be 4.74 µg/m³. This concentration is below the 13-µg/m³ *de minimis* ambient impact level for the 24-hour averaging period. Therefore, a preconstruction monitoring exemption for SO₂ is appropriate in accordance with the PSD regulations.

8.2.3 NO₂

The maximum annual NO₂ impact was predicted to be 0.46 µg/m³. This concentration is below the 14-µg/m³ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for NO₂ in accordance with the FDEP PSD regulations.

8.2.4 CO

The maximum 8-hour CO impact was predicted to be 27.03 µg/m³. This concentration is below the 575-µg/m³ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for CO in accordance with the FDEP PSD regulations.

8.2.5 OZONE

Preconstruction monitoring for ozone is required if potential VOC emissions from a project subject to PSD review exceed 100 tpy. Estimated TEC potential VOC emissions are 119 tpy. Since TEC potential VOC emissions exceed the 100-tpy threshold, current (2002 through 2006) quality-assured ambient ozone data collected at FDEP's ozone monitoring sites in Tallahassee, Leon County, were used to satisfy the PSD preconstruction ambient air monitoring requirements for ozone. Ambient ozone data from these urban area monitoring stations will provide conservative estimates of current ozone air quality for Taylor County (i.e., overestimate actual ambient ozone levels).

8.2.6 FLUORIDES

The maximum 24-hour HF impact was predicted to be $0.04 \mu\text{g}/\text{m}^3$. This concentration is below the $0.25\text{-}\mu\text{g}/\text{m}^3$ *de minimis* ambient impact level for the 24-hour averaging period. Therefore, a preconstruction monitoring exemption for fluorides is appropriate in accordance with FDEP PSD regulations.

9.0 ADDITIONAL IMPACT ANALYSIS

The additional impacts analysis, required for projects subject to PSD review, evaluates project impacts pertaining to associated growth; soils, vegetation, and wildlife; and visibility impairment. Each of these topics is discussed in the following subsections. Based on a thorough review of emissions expected as a result of this project, it is concluded that TEC will not cause any adverse impacts to the soils, vegetation, or wildlife of relevant Class I and II areas.

9.1 GROWTH IMPACTS ANALYSIS

9.1.1 PROJECT GROWTH IMPACTS

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and assess air quality impacts that would result from that growth.

Impacts associated with construction of TEC will be minor. During the approximate 48-month construction period, TEC will employ an average of 642 workers. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

TEC is being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the project are anticipated. When operational, TEC is projected to employ approximately 180 fulltime workers. This number of new personnel will not significantly affect growth in the area. The increase in coal and distillate fuel oil demand due to the operation of TEC will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected at this time.

9.1.2 AREA GROWTH SINCE 1977

U.S. Census data shows that the population of the Taylor County has increased by 29 percent between 1980 and 2005. The 2005 estimated population of Taylor County is 21,310. The population of the city of Perry declined by 19 percent between 1980 and

2005. The 2005 estimated population of the city of Perry is 6,734. In 2004, Taylor County was ranked as the 54th most populous county with a population density ranked 63rd of 67 counties in Florida.

Taylor County has also experienced little industrial growth since 1977. The EPA AirData Web site shows only seven facilities for 1999—the latest year available for facility data. The largest industrial facility, Buckeye, has been operating in Taylor County for over 50 years. The EPA AirData information indicates that Buckeye emissions comprised approximately 90 percent of total Taylor County industrial facility emissions in 1999.

Based on the current low densities of population and industrial activity, it is concluded that air quality in Taylor County has not deteriorated since 1977. As discussed in Section 7.0, the emissions associated with TEC will result in air quality impacts that are well below the national and Florida AAQS.

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

Potential impacts to soils, vegetation, and wildlife resources of the TEC Site and environs resulting from the proposed plant operation include effects of air emissions. Modeled emissions concentrations from the Project for all relevant Class I and II areas are summarized in Table 9-1. In addition, predicted maximum annual nitrogen, sulfur, and mercury deposition values are shown in Table 9-2. As previously discussed, TEC will employ state-of-the-art equipment and emission controls. Maximum air quality impacts in the vicinity of TEC will be well below the applicable AAQS. Given the resulting low emission rates and insignificant potential air quality impacts, potential detrimental effects on soils, vegetation, and wildlife will be insignificant.

A general discussion of air emission impacts on soils, vegetation, and wildlife is provided in the following subsection. Following this general discussion, specific analyses of impacts in the vicinity of TEC as well as each of the five Class I areas located within 300 km are provided.

Table 9-1. Projected Maximum Pollutant Concentration Impacts

Pollutant	Averaging Period	Class I Area Impact ($\mu\text{g}/\text{m}^3$)					Class II Area Impact ($\mu\text{g}/\text{m}^3$)
		St. Marks NWA	Chassahowitzka NWA	Okefenokee NWA	Bradwell Bay NWA	Wolf Island NWA	
NO _x	Annual	0.0209	0.0025	0.0078	0.0093	0.0023	0.67
SO ₂	Annual	0.0263	0.0041	0.0100	0.0123	0.0036	0.50
	24-Hour	0.67	0.16	0.32	0.32	0.1	4.7
	3-Hour	2.41	0.69	0.93	1.09	0.33	14.7
PM ₁₀	Annual	0.0216	0.0053	0.0095	0.0119	0.0040	1.8
	24-Hour	0.27	0.17	0.19	0.20	0.07	19.1
CO	1-Hour	N/A	N/A	N/A	N/A	N/A	49.7
	8-Hour	N/A	N/A	N/A	N/A	N/A	27.0

Source: ECT, 2007.

Table 9-2. Projected Maximum Annual Wet and Dry Atmospheric Deposition Impacts

Pollutant	St. Marks NWA		Chassahowitzka NWA		Class I Area Impacts Okefenokee NWA		Bradwell Bay NWA		Wolf Island NWA		Class II Area Impact ($\mu\text{g}/\text{m}^2/\text{yr}$)
	($\mu\text{g}/\text{m}^2/\text{s}$)	(kg/ha/yr)	($\mu\text{g}/\text{m}^2/\text{s}$)	(kg/ha/yr)	($\mu\text{g}/\text{m}^2/\text{s}$)	(kg/ha/yr)	($\mu\text{g}/\text{m}^2/\text{s}$)	(kg/ha/yr)	($\mu\text{g}/\text{m}^2/\text{s}$)	(kg/ha/yr)	
Nitrogen	0.000048	0.0152	0.000006	0.0018	0.000028	0.0087	0.000023	0.0072	0.00001	0.0033	0.0736
Sulfur	0.000112	0.0354	0.000015	0.0048	0.000054	0.0169	0.000045	0.0141	0.00002	0.0063	
Mercury											

Source: ECT 2007

9.2.1 GENERAL AIR EMISSIONS IMPACTS ON SOILS

Sulfur and nitrogen can be added to soil as a result of atmospheric deposition. Sulfur and nitrogen deposition in soil can have beneficial effects to vegetation if they are currently lacking these elements. At levels above plant requirements, gaseous emission impacts on soils can cause acidic conditions to develop. Acidic conditions in the soil can cause the leaching of basic cations essential for plant life and in extreme circumstances can transform aluminum to a more soluble form where toxicity can occur (Goldstein *et al.*, 1985).

Nitrogen deficiency is common in nonagricultural areas, and, therefore, much of the atmospherically deposited NO_x is biologically assimilated. There is a limited soil adsorption mechanism for nitrate (NO_3), so unutilized nitrate will be leached through the soil (Johnson and Reuss, 1984). Both of these factors indicate that nitrate does not play a significant role in soil acidification, and that sulfate (SO_4) is more of a concern. Atmospheric deposition of nitrogen can facilitate eutrophication of the soil and vegetative community. Critical loads of nitrogen above which eutrophication caused a change in vegetative species present in calcareous forests was found to be 15 to 20 kilograms per hectare per year (kg/ha/yr) (Thimonier *et al.*, 1994).

Sulfur deposition can facilitate soil acidification. Sulfur exists in the soil predominantly in the form of sulfate. The maintenance of sulfate in soil solution facilitates the loss of cations. Therefore, the more sulfate that is adsorbed to soil particles, the more buffered the soils will be (Johnson and Reuss, 1984). The soil is a much larger sink for sulfate than vegetation (Johnson and Reuss, 1984). Sulfate can be adsorbed on the surface of reactive clays and iron/aluminum oxides within the soil, which often releases hydroxide (OH^-), further buffering the soil (Johnson and Reuss, 1984). Soils found in Florida and Georgia that have high adsorption rates for sulfates include ultisols and certain suborders of inceptisols and entisols (Psamments) (Johnson and Reuss, 1984). The high iron and aluminum content of the subsurface spodic (B_h) horizon of spodosols likely adsorbs the sulfate anion to a large extent as is shown to occur with the anion of phosphate. The development of acidic conditions in the Southeast are thought to be well buffered by the high amount of sulfate adsorption (USGS, 1999).

Dissolution of sulfate and nitrate can also facilitate the formation of nitric and sulfuric acid in rainwater, which increases acidic hydrogen ion (H^+) composition within the soil. Soils that are well buffered to the addition of acid causing H^+ ions, have a high cation exchange capacity (CEC), often imparted by surface or subsurface clays and a high base saturation. Barton *et al.* (2002) found soils with a base saturation of 12 to 19 percent and reactive clays, to be buffered to acidic inputs, whereas soils with a base saturation of 3 to 7 percent by depth show the effects of soil acidification. In addition, organic horizons of wetland histosols buffer acidic inputs protecting the depletion of cations from the mineral horizons (Koptsik *et al.*, 1998).

9.2.2 GENERAL AIR EMISSIONS IMPACTS ON VEGETATION

It is difficult to predict site-specific ecological impacts due to air emissions based on data and conclusions in available literature because of significant variations in experimental designs relating dose, duration, and vegetation species. Minor variations in experimental design and the conditions under which the various vegetation species have been fumigated can result in large differences in the tolerance limits of tested species.

Table 9-3 presents a summary of the thresholds for the most sensitive vegetation and the air-pollution induced effects, for important air pollution constituents. To demonstrate the range of tolerances for relevant vegetation, Table 9-4 lists literature results for injury threshold concentrations and characteristic injury symptoms of plants found in the southeastern U.S. The species listed are likely to occur in all or many of the Class I areas addressed herein. As a result, all listed vegetation will be used as bioindicators for impacts to all the Class I and II areas relevant to the TEC Project.

Vegetation damage is described as impacts resulting in foliar damage. Less apparent vegetation injury is described as a reduction in growth and/or productivity without visible damage, as well as changes in secondary metabolites such as tannins and phenolic compounds (Fitzgerald *et al.*, 1996). Vegetation damage often results from acute exposure to pollution (i.e., relatively high doses over relatively short time periods). Injury is also associated with prolonged exposures of vegetation to relatively low doses of pollutants (chronic exposure). Acute damages, which have both functional and visible

Table 9-3. Estimated Maximum Facility Impacts Compared to General Plant Injury Symptoms and Threshold Concentrations for Important Air Pollutants

Pollutant	Symptoms	Injury Threshold		Estimated Maximum Facility Impact ($\mu\text{g}/\text{m}^3$)
		$\mu\text{g}/\text{m}^3$	Sustainable Exposure	
SO ₂	Bleached spots, intercostal chlorosis	131*	8 hours	14.7†† (3-hour)
SO ₂	Absence of the most sensitive lichen	13-26†	Chronic	
NO ₂	Increase in Nitrate Reductase activity in sensitive bryophytes	65‡	24 hours	0.67 ^e (annual)
Mercury	Chlorosis and abscission; brown spotting; yellowing of veins	0.08**	5 weeks	9.8 E-04 ^e

Note: Conservative (worst-case) impact estimated based on modeling results presented in Section 8.0.

Sources: *Jones *et al.*, 1974.
†Wetmore, 1983.
‡World Health Organization, 2000.
**Hindawi, 1970.
††ECT 2007.

Table 9-4. Air Pollutant Injury Threshold Concentrations for Plants Native to the Southeast

Common Name	Scientific Name	SO ₂	NO _x
Red maple	<i>Acer rubrum</i>	786 ^a (5 hours)	
Maple	<i>Acer</i> sp.	524 to 6,550 ^b (8 hours)	
Bald Cypress	<i>Taxodium distichum</i>	2,620 ^c (48 hours)	
Bracken fern	<i>Pteridium aquilinum</i>	131 to 1,310 ^b (8 hours)	
Blackberry	<i>Rubus</i> sp.	131 to 1,310 ^b (8 hours)	
Ragweeds	<i>Ambrosia</i> sp.	1,310 to 2,620 ^h (1 hour) 790 to 1,570 (3 hours)	
Southern red oak	<i>Quercus falcata</i>	1,310 to 2,620 ^h (1 hour) 790 to 1,570 (3 hours)	
Black oak	<i>Quercus velutina</i>	1,310 to 2,620 ^h (1 hour) 790 to 1,570 (3 hours)	
Legumes		1,310 to 2,620 ^h (1 hour) 790 to 1,570 (3 hours)	
Locust	<i>Gleditsia</i> sp.	2,620 to 5,240 ^b (1 hour) 1,570 to 2,100 (3 hours)	
Many crop and garden species		2,620 to 5,240 ^h (1 hour) 1,570 to 2,100 (3 hours)	
American elm	<i>Ulmus americana</i>	131 to 1,310 ^b (8 hours)	
White ash	<i>Fraxinus americana</i>	131 to 1,310 ^b (8 hours)	
Sumacs	<i>Rhus</i> spp.	131 to 1,310 ^b (8 hours)	
Tulip poplar	<i>Liriodendron tulipifera</i>	524 to 6,550 ^b (8 hours)	
Sweetgum	<i>Liquidambar styraciflua</i>	524 to 6,550 ^b (8 hours)	
Slash pine	<i>Pinus elliottii</i>	149 ^f (chronic)	
Basswood	<i>Tilia glabra</i> = <i>T. americana</i>	524 to 6,550 ^b (8 hours)	
Pin oak	<i>Quercus palustris</i>	524 to 6,550 ^b (8 hours)	
Red cedar	<i>Juniperus virginiana</i>	>5,240 ^b (8 hours)	
Potato		2,620 to 5,240 ^h (1 hour) 1,570 to 2,100 (3 hours)	

Table 9-4. Air Pollutant Injury Threshold Concentrations for Plants Native to the Southeast (Continued, Page 2 of 2)

Common Name	Scientific Name	SO ₂	NO _x
Upland cotton	<i>Gossypium hirsutum</i>	>5,240 ^b (1 hour) >2,100 (3 hours)	
Corn	<i>Zea mays</i>	>5,240 ^b (1 hour) >2,100 (3 hours)	
Lichen	<i>Ramalina americana</i>	13 to 26 ^d (chronic)	
Lichens	Sensitive species of <i>Usnea</i> , <i>Lobaria</i> , <i>Cladonia</i>	>30 ^e (chronic)	
White oak	<i>Quercus alba</i>	>5,240 ^b (8 hours)	
Dogwood	<i>Cornus florida</i>	>5,240 ^b (8 hours)	
Bryophyte	Several <i>Bryophyte species</i>		65 ^g (24 hours)
Birch	<i>Betula</i> sp.		120 ^g (chronic)
Common sunflower	<i>Helianthus annuus</i>		375 ^g (chronic)
Alfalfa	<i>Medicago sativa</i>		1,000 ^g (5 hours)
Peach	<i>Prunus persica</i>		>5,240 (1 hour) >2,100 (3 hours)
Garden pea	<i>Pisum sativum</i>		850 ^g (7 hours)
Cultivated tobacco	<i>Nicotiana tabacum</i>		2,000 to 3,000 ^g (3.5 hours)
Perennial ryegrass	<i>Lolium perenne</i>		125 ^g (chronic)
Southern pine	<i>Pinus</i> spp.	1572 ^b (3 hours)	

Note: Concentrations in µg/m³ (exposure times shown in parentheses).

Sources: ^aDavis and Shelly, 1992.

^bJones *et al.*, 1974.

^cShanklin and Kozlowski, 1985.

^dWetmore, 1983.

^eTreshow and Anderson, 1989.

^fHogsett *et al.*, 1985.

^gWorld Health Organization, 2000.

^hEPA, 1982.

consequences, are usually manifested by internal physical damage to foliar tissues. Chronic injuries are typically more associated with changes in physiological processes. The following discussion summarizes descriptions from the literature of the potential effects upon vegetation associated with the relevant pollutants.

9.2.2.1 Nitrogen Oxides

During combustion, atmospheric nitrogen is oxidized to nitrogen oxide (NO) and small amounts of NO₂ (Taylor *et al.*, 1975). Impacts to vegetation from NO₂ result from high concentrations occurring during short time periods (Taylor and MacLean, 1970). Acute exposures of this sort will cause necrotic lesions in leaf tissue and excessive defoliation (MacLean *et al.*, 1968). Non-vascular bryophytes are very sensitive to NO_x exhibiting reductions in nitrate reductase activity at concentrations of 65 µg/m³ with an exposure duration of 24 hours (WHO 2000). Bald cypress (*Taxodium distichum*), a common tree species in wetlands of this geographical area, shows no adverse impacts below 2,620 µg/m³ with an exposure time of 48 hours (Shanklin and Kozlowski, 1985).

9.2.2.2 Sulfur Dioxide

Natural (ambient) background concentrations of SO₂ range between 0.28 and 2.8 µg/m³ on a mean annual basis (Prinz and Brandt, 1985). The most common source of atmospheric SO₂ is the combustion of fossil fuels (Mudd and Kozlowski, 1975). Gaseous SO₂ primarily affects vegetation by diffusion through the stomata (Varshney and Garg, 1979). Small amounts of SO₂ may also be absorbed through the protective cuticle. At low concentrations SO₂ byproducts are effectively detoxified by the plant and can become a sulfur source to the plant, while elevated concentrations can be toxic (Zeiger, 2002). Adverse effects on plants from SO₂ are primarily due to impacts to photosynthetic processes. SO₂ can react with chlorophyll by bleaching or phaeophytinization. This latter process constitutes a photosynthetic deactivation of the chlorophyll molecule. Acute damage due to SO₂ appears as marginal or intercostal areas of dead tissue that at first cause leaves to appear water-soaked (Barett and Benedict, 1970). Chronic injuries are less apparent; the leaves remain turgid and continue to function at a reduced level. In more severe cases of chronic SO₂ exposure, there is some bleaching of the chlorophyll that appears as a mild chlorosis or yellowing of the leaf and/or a silvering or bronzing of the undersurface. Spe-

cies that are categorized as sensitive to SO₂ emissions are those which show damage to at least 5 percent of the leaf area upon being exposed to 131 to 1,310 µg/m³ SO₂ for a period of 8 hours (Jones *et al.*, 1974).

Researchers have conducted numerous studies to determine the effects of SO₂ exposure to a wide variety of selected plant species. A review of the literature demonstrates that the most sensitive vascular plants (e.g., white ash, sumacs, tulip poplar, goldenrods [*Solidago* spp.], legumes, blackberry [*Rubus* spp.], black oak [*Quercus velutina*], and ragweeds [*Ambrosia* spp.]) exhibit visible injury to short-term (3 hours) exposure to SO₂ concentrations ranging from 790 to 1,570 µg/m³. Tolerant plants native to the southeast region are dogwood (*Cornus florida*), red cedar (*Juniperus virginiana*), and white oak (*Quercus alba*) with injury thresholds greater than 5,240 µg/m³ for a 3-hour exposure period (Jones *et al.*, 1974). Plants with intermediate tolerance (131 to 1,310 µg/m³ for an 8-hour period) are maples (*Acer* spp.), tulip poplar (*Liriodendron tulipifera*), and sweetgum (*Liquidambar styraciflua*). Vascular plant species found in this region of the southeast, which are sensitive or moderately sensitive to SO₂, include bracken fern (*Pteridium aquilinum*), blackberry, sumacs (*Rhus* spp.), and tulip poplar. Complicating generalizations regarding SO₂ injury is the observation that the genetic variability of native annual plants can result in the selection of SO₂ resistant strains in as little as 25 years (Westman *et al.*, 1985).

Due to their rather diminutive and inconspicuous nature, lichens and bryophytes are often not considered as important biological components of the ecosystem. However, these nonvascular plants do play a valid role in the environment by functioning as habitat for invertebrates, containing blue-green bacteria that fix nitrogen, participating in mineral cycling, and providing a food source for various fauna, among others.

Nonvascular plants such as lichens and bryophytes are especially important as bioindicators due to well-documented air pollution sensitivity. Because of relatively low chlorophyll content and the absence of the protective covering of a cuticle (common in the leaves of higher plants), nonvascular plants are more sensitive to SO₂ injury. Hart *et al.* (1988) showed that *Ramalina* sp., a lichen genus, exhibited a reduction of CO₂ uptake and biomass gain at SO₂ exposures of 400 µg/m³ for 6 weeks. Tolerant lichens can resist

SO₂ concentrations in the range of 79 to 157 µg/m³; higher concentrations are deleterious to most nonvascular flora (LeBlanc and Rao, 1975). A mean annual concentration of 30 µg/m³ of SO₂ may injure sensitive individuals of some lichen species such as *Usnea*, *Lobaria*, *Ramalina*, and *Cladonia* (Treshow and Anderson, 1989). One lichen species, *Ramalina americana*, is known to be absent where SO₂ concentration mean annual values range from 13 to 26 µg/m³ (LeBlanc and Rao, 1972; Wetmore, 1983).

9.2.2.3 Particulate Matter

In addition to gaseous emissions, small amounts of PM will be emitted by the proposed Project. Typically, the density of PM limits impacts such that only vegetation in proximity to the source may be affected.

Included among the PM may be low concentrations of mercury, beryllium, arsenic, and lead, to the extent present at low levels in coal. The mercury may occur as both mercury vapors and particulates. The mechanism of mercury phytotoxicity is currently under investigation. Past investigations indicate that mercury vapors will cause chlorosis, abscission of older leaves, growth reduction, and poor development. Most investigations have been restricted to greenhouse crops where air quality monitoring was not conducted. One investigation indicates that vegetation exposed to 50 µg/m³ mercury for 7 days experienced leaf abscission (Siegel *et al.*, 1984). Plants found in the region showing injury at this concentration and period of exposure to mercury are willow (*Salix* spp.) and red maple (*Acer rubrum*).

The literature regarding effects on vegetation from beryllium, arsenic, and lead is scarce. One investigation indicates that vegetation growth was reduced by beryllium concentrations in excess of 735 µg/m³ (Gough *et al.*, 1979). Arsenic uptake by vegetation to a concentration of 5 micrograms per gram (µg/g) is considered harmful. Lead retards plant growth above a concentration of 30 µg/g in the soil.

9.2.2.4 Carbon Monoxide

CO is not considered harmful to plants and is not known to be effectively taken up by plants (Bennett and Hill, 1975). Microorganisms within the soil appear to be a major sink for CO.

9.2.3 GENERAL AIR EMISSIONS IMPACTS ON WILDLIFE

Impacts to wildlife can occur due to direct uptake of pollutants through ingestion or via the skin and more indirectly as a result of air pollution induced changes to wildlife habitat and food source. Studies have shown direct air pollution induced injury and death in wildlife as a result of fluoride, cadmium, SO₂, particulates, NO_x, arsenic, mercury, and oxidants like ozone (Newman 1980; Newman & Schreiber 1985). These impacts are mostly the result of extreme incidences due to acute toxicity. This acute toxicity occurs most severely in circumstances where air pollutants were likely elevated far above the AAQS, or where significantly elevated concentrations of pollutants occurred on vegetation that was subsequently consumed. The AAQS were previously shown in Section 3.0 on Table 3-5. Physiological and behavioral effects have been observed at concentrations at or below national standards. No observed impacts upon wildlife are expected at concentrations below the values reported in Table 9-5.

Studies have shown damage to the tracheal epithelium of bird species at extreme concentrations of NO_x and SO₂ of 2,500 µg/m³ and 1,221 µg/m³ respectively (Llacuna *et al.* 1993). These values are far elevated above concentrations that are expected.

Ambient air quality concentrations as a result of TEC will not exceed the NAAQS or values listed in Table 9-5. Pollutant deposition on vegetation at levels harmful to wildlife will likely be lower than plant injury thresholds (Table 9-3 and 9-4). Absent any site-specific studies on baseline levels of pollutants, it is assumed that wildlife impacts will be insignificant if pollutant effects on vegetation are also expected to be insignificant.

Table 9-5. Examples of Reported Stresses to Animals at Air Pollutant Concentrations Below National Secondary Ambient Air Quality Standards

Pollutant	Reported Effect	Concentration ($\mu\text{g}/\text{m}^3$)	Exposure
SO_2^*	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 days/week for 10 weeks continually for 5 months
	Decreased abundance in deer mice	13 to 157	
$\text{NO}_x^{\dagger\dagger}$	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days continually for 2 months
Particulates*	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	2 hours
	Decreased respiratory disease defenses in rats, same with hamsters	100 NiCl_2	

Sources: *Newman and Schreiber, 1988.

$\dagger$ Gardner and Graham, 1976.

$\ddagger$ Trzeciak et al., 1977.

Persistent pollutants such as mercury have the potential to collect in the environment and bioaccumulate to elevated concentrations in upper-trophic level wildlife. Mercury is a persistent pollutant that accumulates in the sediments. Mercury methylation, whereby inorganic forms of mercury are biologically converted to a bioavailable organic form, occurs most predominantly in the anaerobic conditions found in ponds, lakes, and wetlands (St. Louis *et al.*, 1994; Krabbenhoft *et al.*, 1995; Driscoll *et al.*, 1998). As a result, species living and feeding within these aquatic systems are the most sensitive to mercury bioaccumulation.

Most impacts to wildlife due to emissions from power plants are indirect, predominantly as a result of effects on habitat quality. One such indirect effect is increased acidification. Amphibians are particularly sensitive to increased acidification in vernal pools and ponds as a result of the permeability of their skin. The highest potential for acidification to impact amphibian egg-laying habitat occurs in snow-melt water pools, which do not occur in the project area (Schreiber and Newman, 1988). Loss of fish, amphibians, algae, invertebrates, and vegetative habitat as a result of acidification can impact species further up the food chain such as fish-eating feral mink (Bevanger and Albu, 1986) and wetland waterfowl (Rattner *et al.*, 1987). These studies indicate that the greatest possible impact to wildlife as a whole is degradation of the composition, structure, and habitat value due to increased acidification of the soils and aquatic systems caused by elevated SO_x and NO_x. As discussed in subsequent sections, the atmospheric concentrations of SO_x and NO_x and deposition of sulfur and nitrogenous compounds as a result of this Project are unlikely to cause soil and water acidification.

9.2.4 SPECIFIC AIR EMISSIONS IMPACTS IN THE VICINITY OF TEC

9.2.4.1 Vegetation Impact Evaluation

A description of the vegetative community in the vicinity of TEC is provided Section 2.3.5 of the SCA.

Nitrogen Oxides

Vegetation most sensitive to nitrogen oxides are bryophytes, which have NO₂ tolerances of 65 µg/m³ for 24 hour exposure (Table 9-3). The maximum annual average NO₂ air

quality impact projected for TEC of $0.67 \mu\text{g}/\text{m}^3$ (Table 9-1) is well below the NAAQS of $100 \mu\text{g}/\text{m}^3$ (0.0523 ppm) (Table 3-5), and lower than the thresholds of sensitive bryophytes (Table 9-3). As such, no significant vegetative impacts are likely to occur as a result of NO_x emissions from the Project.

Sulfur Dioxide

Sensitive vegetative species show damage to at least 5 percent of their leaf area upon exposures of 131 to $1,310 \mu\text{g}/\text{m}^3$ SO_2 for a period of 8 hours (Table 9-4). One species of lichen (*Ramalina Americana*) has been shown to be absent at concentrations from 13 - $26 \mu\text{g}/\text{m}^3$ with chronic, long-term exposures (Table 9-4). The maximum TEC air quality impacts for averaging times of 3 hours, 24 hours, and annual durations of 14.7, 4.7, and $0.50 \mu\text{g}/\text{m}^3$ (Table 9-1), respectively, result in impacts that are well below the 24-hour and annual AAQS of 0.10 ppm ($260 \mu\text{g}/\text{m}^3$) and 0.02 ppm ($60 \mu\text{g}/\text{m}^3$), respectively (Table 3-5). The most sensitive vascular plants will not exhibit injury symptoms until concentrations increase to values of at least $131 \mu\text{g}/\text{m}^3$ for 8 hours (Table 9-3) much more than the modeled values of $4.7 \mu\text{g}/\text{m}^3$ for 8 hours (Table 9-1). Vascular plants are not expected to be affected by emissions from the TEC Project.

PM₁₀

PM₁₀ concentrations are projected to increase in the project vicinity by 1.82 and $19.05 \mu\text{g}/\text{m}^3$, for annual and 24 hour durations, respectively (Table 9-1). NAAQS standards for PM₁₀ are $150 \mu\text{g}/\text{m}^3$ for a 24-hour duration (Table 3-5). Florida's PM₁₀ AAQS standards are $150 \mu\text{g}/\text{m}^3$ and $50 \mu\text{g}/\text{m}^3$ for 24 hour and annual averaging periods, respectively. TEC emissions are well below these AAQS standards. Therefore, no adverse impacts to vegetation are expected in the project vicinity as a result of particulate matter emissions.

CO

CO is not considered harmful to plants and is not known to be effectively taken up by plants (Bennett and Hill, 1975). In addition, the TEC CO air quality impacts of $0.04973 \text{ mg}/\text{m}^3$ ($49.73 \mu\text{g}/\text{m}^3$) and $0.02703 \text{ mg}/\text{m}^3$ ($27.03 \mu\text{g}/\text{m}^3$) for durations of 1 hour and 8 hour (Table 9-1) respectively, are orders of magnitude smaller than the 1 hour and 8 hour

primary NAAQS of 40 mg/m³ and 10 mg/m³, respectively (Table 3-5). Therefore, no adverse impacts to vegetation are expected as a result of CO emitted by TEC.

9.2.4.2 Wildlife Impact Evaluation

A description of wildlife in the vicinity of TEC is discussed in Section 2.3.6 of the SCA.

Air pollutant concentrations in the project vicinity are projected to be significantly lower than NAAQS standards and minimum threshold concentrations (Table 9-5), below which no wildlife acute toxicity is expected to occur. Most effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed in Section 9.2.4.1, minimal impacts to vegetation are expected to occur as a result of TEC. Therefore, no adverse impacts to wildlife are expected.

Mercury deposition in the area surrounding the Project is projected to be 0.0736 microgram per square meter per year (µg/m²/yr), at a maximum (Table 9-2). This value is an order of magnitude smaller than average conservative estimates for background deposition rates of 0.5 to 1 µg/m²/yr as reported in the literature (Bindler, 2003). Therefore, direct impacts to wildlife should be less than normal background deposition.

9.2.4.3 Soil Characteristics

Soil types in Taylor County have been mapped by USDA/NRCS in 1995. Upland soils surrounding the project site have been identified and predominantly include:

- Leon Fine Sand.
- Albany Fine sand.
- Ousley-Leon-Clara.

Wetland soils within the vicinity of the project site include:

- Wesconnectt-Evergreen-Pamlico.
- Clara-Bodiford.
- Surrency-Starke-Croatan.
- Dorovan-Pamlico.

Overall, Leon is the dominant soil type in the surrounding area. The Wesconnectt-Evergreen-Pamlico and Dorovan-Pamlico complexes are dominant in the isolated depressional wetlands. The Ousley-Leon-Clara complex exists as a natural upland levee that

runs parallel to the Fenholloway River. The soil pH and relevant chemical properties of each soil, where listed in soil surveys, are shown in Tables 9-6 and 9-7, respectively.

The Leon Fine Sand is an extremely acid to slightly acid soil that forms from sandy marine deposits on lowlands in the coastal plain. The soil series is spodosol, which is indicative of the poor drainage of this soil. The native vegetative community found on this soil is the North Florida Flatwoods, which consists of slash pine and live oak, with an understory of saw palmetto, gallberry, and grasses.

The Ousley-Leon-Clara map unit consists of soils that form from sandy marine deposits that become loamier where the Ousley series occurs. These soils form on lowlands in the coastal plain. The Ousley and Clara series form the psamment subgroup of the entisol series. The ecological community within the Leon-Clara parts of the complex consists of the North Florida Flatwoods vegetation listed previously. The Ousley series supports a native community of Upland Hardwood Hammocks. This vegetative community includes black cherry, eastern hornbeam, flowering dogwood, hawthorns, laurel oak, laurelcherry, live oak, loblolly pine, longleaf pine, slash pine, pignut hickory, southern magnolia, sweetgum, and water oak with an understory of American beautyberry, arrowwood, sparkleberry, and wax myrtle.

Soils defined as Albany Fine Sand range from extremely acid to slightly acid in surface horizons and extremely acid to moderately acid in subsurface soils. These soils form from sandy and loamy marine deposits and occur in rises and knolls within the lowlands of the coastal plain. The soil series is ultisol. The native vegetative community that this soil supports is the Upland Hardwood Hammocks, described previously.

Soils mapped within the Wesconnectt-Evergreen-Pamlico complex consist of the extremely acid to strongly acid soils found within the Pamlico and Evergreen soil series to the extremely acid to slightly acid soils found within the Wesconnectt soil series. All of these soils occur in depressional wetlands, with a surface horizon containing an elevated organic matter content underlain by sandy marine deposits. The Pamlico soil is a histosol,

Table 9-6. Soil pHs for the Soils Found in the TEC Vicinity

Soil	Depth (inches)	Soil reaction (pH)
<u>Leon Fine Sand</u>	0 to 80	3.6 to 6.5
<u>Ousley-Leon-Clara</u>		
Ousley	0 to 80	4.5 to 6.0
Leon	0 to 80	3.6 to 6.5
Clara	0 to 80	5.1 to 8.4
<u>Albany Fine Sand</u>	0 to 50	3.6 to 6.5
	50 to 80	3.6 to 6.0
<u>Wesconnectt-Evergreen-Pamlico</u>		
Wesconnectt	0 to 80	3.6 to 6.5
Evergreen	0 to 80	3.6 to 5.5
Pamlico	0 to 80	3.6 to 5.5
<u>Surrency-Starke-Croatan</u>		
Surrency	0 to 80	3.6 to 5.5
Starke	0 to 80	3.6 to 6.0
Croatan	0 to 25	<4.5
	25 to 80	3.5 to 6.5
<u>Clara-Bodiford</u>		
Clara		5.1 to 8.4
Bodiford	0 to 12	3.6 to 7.3
	12 to 18	6.1 to 7.8
	18 to 29	6.6 to 7.8
	29 to 51	6.6 to 8.4
	51 to 80	—
<u>Dorovan-Pamlico</u>		
Dorovan	0 to 72	3.6 to 4.4
	72 to 80	3.6 to 5.5
Pamlico	0 to 80	3.6 to 5.5

Source: United States Department of Agriculture, Natural Resources Conservation Service (USDA, NRCS) Taylor County Soil Surveys, 2000.

Table 9-7. Chemical Properties of the Soils within the Project Site Vicinity

Soil	Depth (cm)	Horizon	Cadmium	Magnesium	Sodium	Potassium	CEC	Base Saturation
Leon Fine Sand	0 to 15	Ap	0.9	0.23	0.03	0.03	12.11	10
	15 to 28	E1	0.19	0.03	0.01	0.01	1.89	13
	28 to 64	E2	0.05	0.01	0	0	1.13	5
	64 to 76	Bh1	0.29	0.07	0.03	0.01	18.01	2
	76 to 86	Bh2	0.17	0.04	0.01	0.01	15.1	2
	86 to 142	C1	0.04	0.02	0	0.01	5.03	1
	142 to 203	C2	0.05	0.01	0.01	0	2.03	4
Albany Fine Sand	0 to 25	Ap	0.4	0.02	0.03	0.04	9.51	5
	25 to 66	E1	0.09	0.01	0.02	0.02	5.04	3
	66 to 94	E2	0.04	0.01	0.03	0.02	2.99	3
	94 to 127	E3	0.05	0.01	0.02	0.02	1.61	6
	127 to 145	Bt	0.36	0.03	0.04	0.05	4.14	12
	145 to 175	Btg1	0.64	0.23	0.05	0.09	9.49	11
	175 to 203	Btg2	0.29	0.08	0.04	0.08	8.07	6
Wesconnectt-Evergreen-Pamlico Pamlico	0 to 23	Oe and Oa1	2.65	1.4	0.36	0.49	191.19	3
	23 to 56	Oa2	0.61	0.14	0.13	0.04	155.16	1
	56 to 64	2C1	0.09	0.03	0.01	0	8.29	2
	64 to 152	2C2	0.03	0.01	0	0	3.12	1

Source: United States Department of Agriculture, Natural Resources Conservation Service (USDA, NRCS) Taylor County Soil Surveys, 2000.

while the Evergreen and Wesconnectt are classified within the spodosol series. The native vegetative community consists of a dense growth of evergreen shrubby vegetation including gallberry, fetterbush, myrtleleaved holly, titi, greenbriers, sweetpepperbush, and sweetbay as is typical of shrub-bogs/bay swamps.

Soils of the Surrency-Starke-Croatan complex form from sandy and loamy marine sediments. Soils classified within the Croatan series have an organic surface horizon and are histosols. Surrency and Starke soils are ultisols. Soils within this complex range from extremely acid to slightly acid. The vegetation consists of species listed previously for the shrub-bog/bay swamp community.

The Clara-Bodiford complex form in floodplains and depressions. Clara soils form from sandy marine sediments and are classified within the psamments subgroup of the entisols. The Bodiford series is classified as an alfisol, indicative of sandy, loamy parent material underlain by limestone bedrock. Both soils are acidic in surface horizons but soils of the Bodiford series increase in alkalinity in subsurface soils as influenced by the limestone bedrock. The vegetative community is a shrub-bog/bay swamp community.

Dorovan-Pamlico soils are extremely acidic histosols, which consist of an organic horizon underlain by sandy marine deposits. The vegetative community is a shrub-bog/bay swamp community.

In general, soils in the project vicinity range from extremely acid to slightly acid, with the exception of the Clara-Bodiford complex, which tends to be more alkaline as a result of limestone bedrock.

Soils Impact Evaluation

Leon is the dominant soil in the vicinity of the Project occurring throughout the uplands. This soil has a moderately high cation exchange capacity in the surface horizon as well as the subsurface organometallic spodic horizon. In addition, the surface horizon of the dominant Leon soil has a cation exchange capacity in the range where sensitivity to changes in pH have been shown to be reduced (Barton *et al.*, 2002). As a result of these

chemical properties, it is likely that the Leon soil, which is dominant on the Site, will not be adversely impacted by TEC.

The dominant soils in the wetlands are the Wesconnectt-Evergreen-Pamlico and the Dorovan-Pamlico. The high organic content of the histic epipedon in the Pamlico imparts an immense cation exchange capacity on the surface soils. In addition, the organic matter in this horizon imparts a large sulfate adsorption capacity that will buffer this soil to changes in pH. This soil profile, defined by a histic epipedon, is typical of the other wetland soils in the project vicinity (Wesconnectt-Evergreen-Pamlico, Surrency-Starke-Croatan, Clara-Bodiford) and subsequently these soils are likely well buffered as well. Therefore, it is concluded that the hydric/wetland soils of the TEC Project vicinity will not be adversely affected by TEC.

9.2.5 SPECIFIC AIR EMISSIONS IMPACTS—CLASS I AREAS

The following describes environmental features and a discussion of potential impacts to Class I areas located within 300 km of the proposed project site as a result of TEC emissions. There are five Class I areas within this range including the Okefenokee, Chassahowitzka, St. Marks, Wolf Island, and Bradwell Bay National Wilderness Areas (NWAs). This portion of the analysis will focus on the potential impacts to air quality-related values (AQRVs) within these public lands. AQRVs are defined as:

“All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. The values include visibility and those scenic cultural, biological, and recreational resources of an area that are affected by air quality. Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are assets that are to be preserved if the area is to achieve the purposes for which it was set aside” (Federal Register, 1978).

This study will focus on the vegetation, wildlife, and soils of these five NWAs.

9.2.5.1 Okefenokee NWA

Vegetation Types

The Okefenokee National Wilderness Area (ONWA) consists predominantly of a large swamp with a diversity of wetland communities, intermixed with vegetated islands and a few uplands. The vegetative communities as listed in the ONWA Comprehensive Conservation Plan are described in the following (FWS, 2006).

Broadleaved Hardwoods

This vegetative community covers a large portion of the northwest side of the swamp. The canopy of evergreen, deciduous, and broadleaved trees limits understory vegetation. The canopy consists predominantly of Blackgum (*Nyssa sylvatica*) and Cypress (*Taxodium* spp.). In addition the vegetation consists of loblolly bay (*Gordonia lasianthus*), red bay (*Persea borbonia*), sweet bay (*Magnolia virginiana*), largeleaf gallberry (*Ilex coriacea*), and dahoon holly (*Ilex cassine*) with a sphagnum moss groundcover.

Cypress/Hardwoods

This community consists of unlogged virgin pond cypress (*Taxodium ascendens*) wetlands and logged areas where cypress recruitment is high enough to be separated from broadleaved hardwoods. The understory vegetation is similar to broadleaved hardwoods.

Mixed Wetland Pine

The mixed wetland pine community is defined by a presence of at least 30-percent slash pine (*Pinus elliottii*) in the canopy mixed with other vegetation types. Associated vegetation includes blackgum, loblolly bay, sweet bay, and a variety of ferns.

Scrub/Shrub

The scrub/shrub ecosystem consists of many species of evergreen and deciduous shrubs intermixed with even-aged stands of young, small trees. Evergreen and deciduous shrubs found in this vegetation type include hurrah bush (*Lyonia leucothoe*), dahoon holly, largeleaf gallberry, gallberry (*Ilex glabra*), titi (*Cyrilla racemiflora*), buttonbush (*Cephalanthus occidentalis*), poor man's soap (*Clethra alnifolia*), Virginia sweetspire (*Itea vir-*

ginica), fetterbush (*Leucothoe racemosa*), and highbush blueberry (*Vaccinium fuscatum*). Scrub trees include cypress, blackgum, and bay.

Prairie

Prairies are consistent with communities that are usually described as freshwater marsh. There are two types of prairie communities: aquatic macrophyte prairie and herbaceous prairie. The aquatic macrophyte prairie contains water lily (*Nymphaea odorata*), spatterdock (*Nuphar lutea*), floating heart (*Nymphoides aquatica*), pickerel weed (*Pontederia cordata*), golden club (*Orontium aquaticum*), wampee (*Peltandra virginica*), pipewort (*Eriocaulon compressum*), yellow-eyed grass (*Xyris smalliana*), sphagnum moss species (*Utricularia* spp.), as well as algae.

The herbaceous prairie is dominated by sedges. In addition chain fern (*Woodwardia virginica*), pitcher plants (*Saracenia* spp.), swamp loosestrife (*Decodon verticillatus*), paint root (*Lachnanthes tinctoria*), wampee, golden club, water lily, pipewort, and yellow eyed grasses.

Upland Hardwoods

Upland hardwoods contain a variety of scrub oaks that are found in sandhills and sandy ridges.

Longleaf Pine

Longleaf pine comprises 70 percent of the basal area of this forest type. The vegetative composition of this community is predominantly defined by the recurrence of fire. Longleaf pine (*Pinus palustris*) and wiregrass (*Aristida stricta*) occur where fire is frequent. In regions surrounding ponds and wetlands where fire is less common, slash pine, loblolly pine, and pond pine (*Pinus serotina*) occur. In addition, several other hardwoods can be found in this community including several scrub oaks species, black gum, persimmon (*Diospyros virginiana*), and sweetgum (*Liquidambar styraciflua*).

Longleaf/Mixed Pine

A total of 35 to 70 percent of the basal area consists of pine trees in longleaf/mixed pine forests. This is a transitional forest where slash, loblolly, and pond pines intermix with longleaf pines.

Mixed Pine/Longleaf Pine

This vegetation type occurs primarily where longleaf pine was logged and/or where fire was suppressed to allow invasion by slash, loblolly, or pond pines from wetter regions. As a result longleaf pine makes up less than 35 percent of the basal area.

Mixed Pine

The longleaf pine component has been replaced by slash, loblolly, and pond pine in mixed pine forests. Other associated species includes sweetbay, swamp tupelo (*Nyssa sylvatica*), pond cypress, pond pine, loblolly bay, live oak (*Quercus virginiana*), red maple (*Acer rubrum*), water oak (*Quercus nigra*), and laurel oak (*Quercus hemisphaerica*).

The hairy rattleweed (*Baptisia arachnifera*) is the only endangered plant species within ONWA, and the parrot pitcher plant (*Sarracenia psittacina*), a threatened species, is found there. There are four Georgia species of special concern found within ONWA including silver buckthorn (*Sideroxylon alachuense*), greenfly orchid (*Epidendrum conopseum*), fly catcher/golden trumpet (*Sarracenia flava*), and the hooded pitcher plant (*Sarracenia minor*).

Vegetation Impact Evaluation

The EPA monitors NO₂, PM₁₀ and SO₂ at monitoring stations across the nation. These data are publicly available at the EPA Web site (<http://www.epa.gov/air/oaqps/montring.html#attainment>). These data will be referred to throughout this discussion to determine baseline concentrations. These stations are monitored for a determination of nonattainment areas based on the NAAQS (Table 3-5). Monitoring stations are spread throughout the region, which makes it difficult to determine the relevance of monitored concentrations to impacts at the ONWA. Nevertheless, monitoring stations in the closest proximity will be utilized to place emissions values in

perspective. NO₂ concentrations in Jacksonville, Florida, remain approximately one-fifth the national standard of 0.053 ppm (100 µg/m³) (Table 3-5) and below the vegetative injury threshold of 65 µg/m³ with a 24-hour duration (Table 9-3). The TEC Project is projected to have a maximal annual increase in atmospheric NO₂ concentration within the ONWA of 0.0078 µg/m³ (Table 9-1). This is well below concentrations where any potential vegetative impact to the refuge is likely to occur (Table 9-3). SO₂ monitored at the aforementioned sites consistently remains well below the national standard of 0.03 ppm (80 µg/m³) (Table 3-5). The Project is modeled to increase the maximum 3-hour, 24-hour, and annual atmospheric SO₂ concentrations by 0.93, 0.32, and 0.01 µg/m³, respectively (Table 9-1). As shown in Table 9-4, the species most sensitive to SO₂ within an 8-hour duration are American elm and white ash, although injury does not occur until concentrations exceed 131 µg/m³ (Table 9-4), which is well above the projected increase (0.93 µg/m³) as a result of TEC. Lichens which are more sensitive to chronic exposure do not exhibit injury symptoms until concentrations exceed 13 µg/m³ (Table 9-4). Therefore, it is unlikely that vegetation in ONWA will be adversely impacted by TEC SO₂ impacts.

Average annual PM₁₀ concentrations at Jacksonville have never exceeded the Florida/Georgia annual AAQS standard of 50 µg/m³ (Table 3-5). Maximum PM₁₀ emissions as a result of the Project (Table 9-1) are several orders of magnitude lower than national standards (Table 3-5).

Typical Wildlife

The ONWA is home to 48 species of mammals, 200 birds, 33 fish, 101 species of reptiles and amphibians, and many species of invertebrates. The refuge was originally established for the conservation of birds, and there are a variety of migratory and resident birds. Birds found within the refuge include wood ducks, osprey, swallow-tailed kites, as well as a variety of wading birds including great egrets, great blue herons, white ibis, and little blue herons. The refuge is a temporary stopping point for many migrating waterfowl, although populations are not as great as other coastal wetlands within the east coast. Species of waterfowl found in the refuge include ring-necked ducks, mallards, blue-winged, and green-winged teal and wood ducks. Listed bird species known to occur in the ONWA

include the red-cockaded woodpecker, and one swallow-tailed kite nest was also found. In addition, the swamp has both resident and migratory sandhill cranes.

There are some notable large mammals present in the ONWA. Florida black bear, white-tailed deer, the round-tailed muskrat, and the Rafinesque's big-eared bat have been observed on the property. The dominant fish species present on the property include the bowfin and the flier comprising 88 percent of the catch. Overall, 36 species of fish have been identified. The wetlands of the ONWA facilitate a diverse amount of herptofauna and reptiles including the American alligator and many species of frogs and turtles. Ephemeral ponds support the flatwoods salamander, the striped newt, the gopher frog, and other species. Federally listed species include indigo snakes along with American alligator. Other rare or sensitive species that can be found include the gopher tortoise, pine snake, eastern hognose, diamondback rattlesnake, and eastern glass lizard.

Wildlife Impact Evaluation

Air pollutant concentrations in the project vicinity are projected to be well below NAAQS standards and minimum threshold concentrations (Table 9-5), below which no wildlife acute toxicity is expected to occur. Most air pollution effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed above, minimal impacts to vegetation are expected to occur as a result of the low emissions increases in ONWA. Therefore, no adverse impacts to wildlife are expected.

Mercury deposition is monitored in the ONWA via the Mercury Deposition Program (MDP). Annual average mercury deposition values are shown in Figure 9-1. Natural conservative background mercury deposition levels determined from accumulated peat are 0.5 and 1 microgram per square meter per year ($\mu\text{g}/\text{m}^2/\text{yr}$), as listed in literature (Bindler, 2003). The annual mercury deposition values shown in Figure 9-1 are at the lower end of this range. Mercury methylation, whereby mercury is transformed in to an organic toxic form, is accelerated in wetlands like Okefenokee (St. Louis *et al.*, 1994; Krabbenhoft *et al.*, 1995; Driscoll *et al.*, 1998). Mercury contamination within the Suwannee River, which is fed by the ONWA, has been an ongoing problem. Studies in the Okefenokee swamp have found mean mercury concentration in fish tissues of 0.359 ± 0.21 mg/L (wet

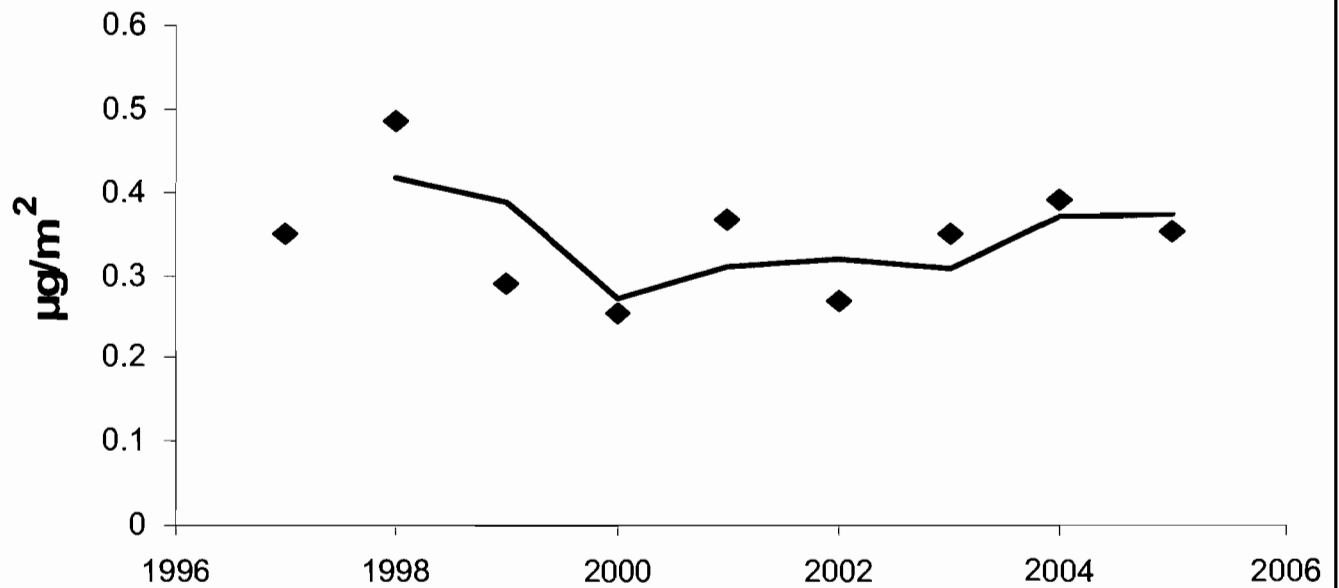


FIGURE 9-1.

MDP WET DEPOSITION VALUES AND MOVING AVERAGE
TRENDLINE FOR MERCURY WITHIN THE ONWA

Source: ECT, 2005.



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weight) (Mason and Bowers, 1995). The presence of mercury in the ONWA is thought to occur as a result of wet and dry atmospheric deposition.

As discussed previously, the mercury deposition rate as a result of the TEC Project ($0.0736 \mu\text{g}/\text{m}^2/\text{yr}$ maxima) (Table 9-2) in the vicinity of TEC is an order of magnitude lower than natural background deposition (0.5 to $1 \mu\text{g}/\text{m}^2/\text{yr}$) (Bindler 2003) and existing deposition (shown in Figure 9-1). It is safe to assume that mercury deposition at the distant ONWA will be much lower than the small amount emitted in the vicinity of TEC, where it was deemed that no wildlife impacts are projected to occur. Therefore, it is concluded that there will be no adverse impacts to wildlife from mercury within ONWA as a result of TEC.

Soil Characteristics

Soil types within the ONWA change with their elevation along a gradient from wetlands to uplands, with corresponding changes in vegetation. Soil series present in the ONWA are Dasher, Pamlico, Croatan, Allanton, Lynn Haven, Surrency, Plummer, Pelham, Sapelo, Leon, Mascotte, Olustee, Mandarin, and Ridgeland (FWS, 2006). NRCS/USDA soil surveys were utilized where found to compile a table of soil pHs (Table 9-8) and relevant soil chemical properties such as CEC and base saturation (Table 9-9). None of the counties in Georgia where the ONWA is present have published soil surveys. As a result, all data was taken from Baker County, Florida. The soils listed are histosols in the permanently inundated areas with ultisols in the intermediate elevations and spodosols in the highest elevations.

Soils Impact Evaluation

Dominant soil types (Histosols, Ultisols and Spodosols) have a high degree of sulfate adsorption capability, increasing their buffering capacity to changes in pH (Johnson and Reuss, 1984). The soils by their very nature have a low pH, base saturation, and CEC, and it is likely that the vegetation is adapted to these low pH, low fertility conditions.

As discussed previously, soils are impacted by air pollution predominantly as a result of wet and dry atmospheric deposition of sulfur and nitrogen containing compounds and

Table 9-8. Soil pHs for the Soils Found on ONWA

Soil	Depth (inches)	Soil Reaction
Dasher	0 to 80	3.6 to 4.4
Allanton	0 to 80	3.6 to 5.5
Leon	0 to 80	3.6 to 6.5
Mandarin	0 to 80	3.6 to 6.0
Mascotte	0 to 80	3.6 to 5.5
Olustee	0 to 80	3.6 to 5.5
Pamlico	0 to 18	3.6 to 4.4
	18 to 80	3.6 to 5.5
Pelham	0 to 80	3.6 to 5.5
Plummer	0 to 80	3.6 to 5.5
Sapelo	0 to 80	3.6 to 5.5
Surrency	0 to 28	3.6 to 5
	28 to 80	3.6 to 5.5

Source: USDA, NRCS soil surveys of Baker County, Florida 1996.

Table 9-9. Chemical Properties of the Soils Within the ONWA

Soil	Depth (cm)	Horizon	Ca	Mg	Na	K	CEC	Base Saturation
Leon	0 to 7	A1	0.25	0.11	0.02	0.01	4.83	8
	7 to 21	A2	0.04	0.01	0.01	0	1.05	6
	21 to 24	Bh1	0.04	0.01	0	0	23.83	—
	24 to 26	Bh2	0.03	0.01	0.01	0	12.35	—
	26 to 38	BC	0.02	0.01	0	0	2.96	1
	38 to 47	E	0.02	0.01	0	0	3.52	1
	47 to 55	B'h1	0.01	0.01	0	0	2.78	1
	55 to 80	B'h2	0.03	0.01	0	0	5.83	1
Mascotte	0 to 6	A	0.7	0.22	0.04	0.06	10.65	10
	6 to 18	E	0.06	0.02	0	0	1.24	6
	18 to 20	Bh1	0.12	0.04	0.02	0.02	13.61	1
	20 to 24	Bh2	0.06	0.02	0	0	24.24	0
	24 to 29	BE	0.03	0.02	0	0	3.86	1
	29 to 38	E'	0.03	0.03	0	0	0.35	17
	38 to 52	Btg1	0.09	0.14	0	0.02	6.42	4
	52 to 56	Btg2	0.03	0.04	0	0.01	15.83	1
	56 to 80	C	0.02	0.01	0	0.01	17.84	0
Olustee	0 to 8	Ap	0.19	0.08	0.03	0.04	5.76	6
	8 to 14	Bh	0.04	0.02	0.03	0.01	4.42	3
	14 to 27	E1	0.02	0.02	0.03	0	1.67	4
	27 to 37	E2	0.02	0.02	0.03	0	2.55	3
	37 to 57	Btg1	0.15	0.29	0.05	0.02	5.32	10
	57 to 80	Btg2	0.18	1.07	0.09	0.01	6.3	21
Sapelo	0 to 6	A	0.12	0.1	0	0.02	3.8	6
	6 to 18	E	0.05	0.03	0	0.01	1.39	6
	18 to 22	Bh1	0.08	0.06	0.02	0.02	3.49	5
	22 to 26	Bh2	0.07	0.02	0	0.01	20.27	0
	26 to 31	BE	0.03	0.01	0	0	5.24	1
	31 to 48	E'	0.04	0.01	0	0.01	0.6	10
	48 to 55	Btg1	0.04	0.02	0	0.01	3.89	2
	55 to 70	Btg2	0.09	0.09	0	0.02	5.95	3
	70 to 80	C	0.08	0.11	0	0.01	4.2	5

Source: USDA, NRCS soil surveys of Baker County, Florida 1996.

other trace elements such as mercury. This can contribute to acidification, eutrophication, and other effects. Atmospheric wet deposition is monitored at the ONWA through the National Atmospheric Deposition Program (NADP). Annual average wet deposition, not including dry deposition values, for nitrate and SO₃ since monitoring began are shown in Figures 9-2 and 9-3.

NADP monitoring of annual average nitrate deposition values are between approximately 8 to 12 kg/ha/yr (Figure 9-2). This is below the threshold of 15 to 20 kg/ha/yr where it was determined eutrophication would occur (Thimonier *et al.*, 1994). A modeled increase in maximum nitrogen deposition of 0.0087 kilogram per hectare per year (kg/ha/yr) (Table 9-2) as a result of TEC would have a negligible impact on the soils of the refuge. NADP monitoring of sulfite has measured annual sulfite wet deposition of approximately 8-18 kg/ha/yr (Figure 9-3). Sulfur atmospheric wet and dry deposition within the ONWA due to TEC is projected to increase at a maximum of 0.0169 kg/ha/yr (Table 9-2). This concentration increase is not significant enough to cause any measurable impact on soils or ecosystem health.

9.2.5.2 Chassahowitzka NWA

Vegetation Types

The predominant vegetative communities that are represented in the Chassahowitzka National Wilderness Area (CNWA) include hardwood swamps, cypress ponds, flatwoods, saltmarsh, sandhill, scrub, and wet prairies (FWC, 2001).

Hardwood Swamp

The hardwood swamp is the most prevalent vegetative community in the CNWA. This community is a palustrine wetland community characterized by the diverse mixture of trees, shrubs, and vines that vary with the differences in elevation. Dominant tree species include bald cypress (*Taxodium distichum*), red maple (*Acer rubrum*), sweet gum (*Liquidambar styraciflua*), winged elm (*Ulmus alata*), southern magnolia (*Magnolia grandiflora*), ashes (*Fraxinus* spp.), and southern red cedar (*Juniperus silicicola*). The subcanopy includes redbud (*Cercis canadensis*) and basswood (*Tilia* spp.) in higher elevation sites and red bay (*Persea borbonia*), swamp dogwood (*Cornus foemina*), and

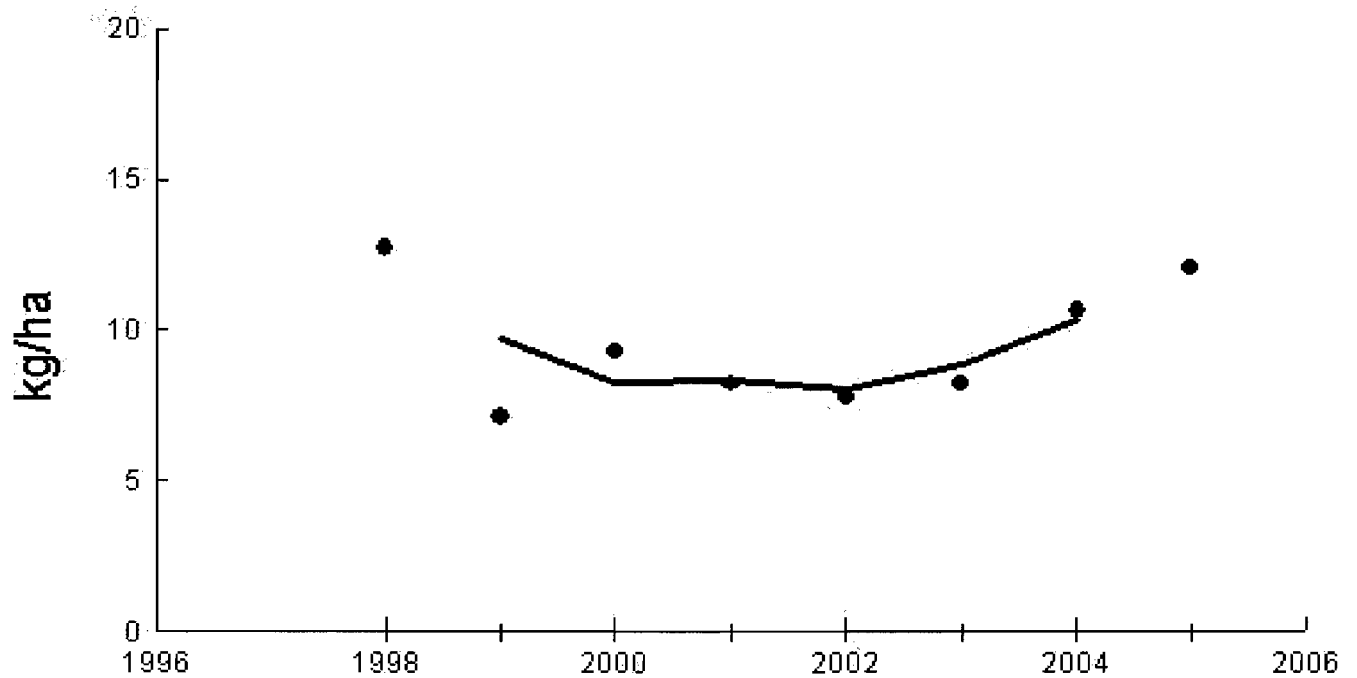


FIGURE 9-2.
NADP ANNUAL WET DEPOSITION VALUES AND
3-YEAR WEIGHTED AVERAGE TRENDLINE FOR
NITRATE WITHIN ONWA

Source: ECT, 2005.

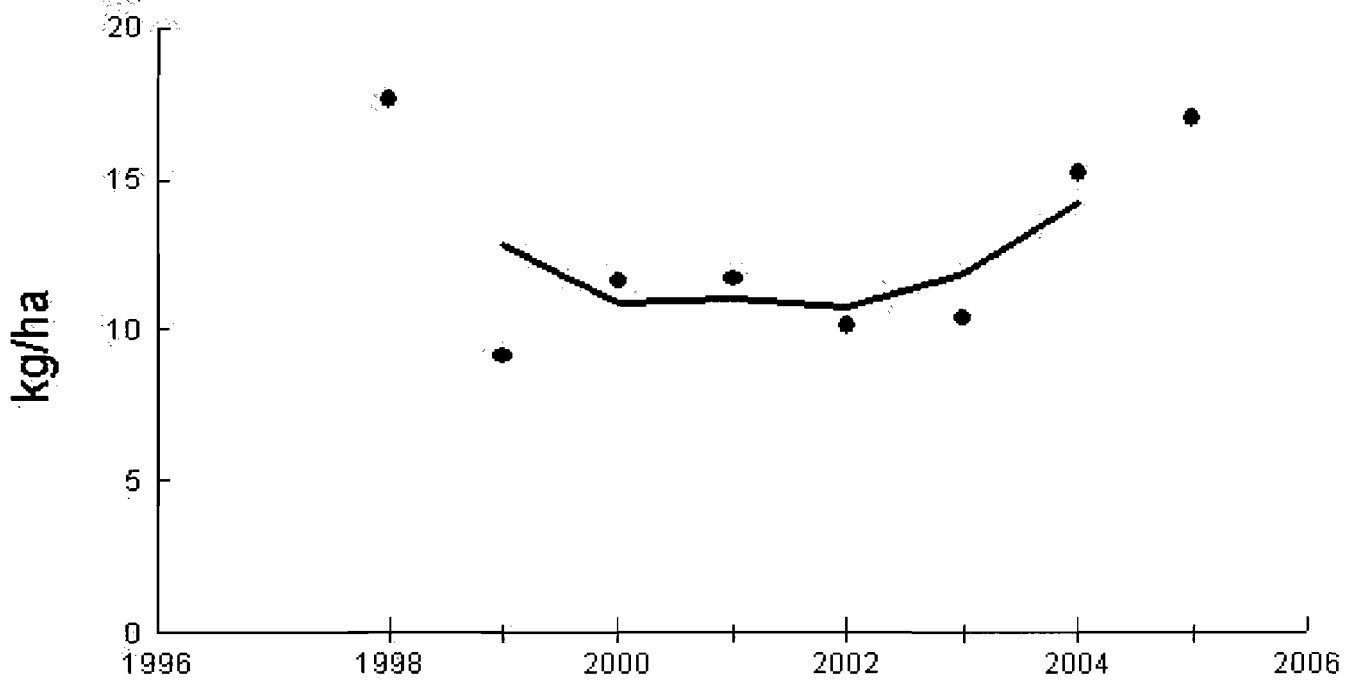


FIGURE 9-3.
NADP WET DEPOSITION VALUES AND 3-YEAR
WEIGHTED AVERAGE TRENDLINE FOR SO_3
WITHIN THE ONWA

Source: ECT, 2005.



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dahoon holly (*Ilex cassine*) in lower elevations. The understory vegetation consists of dwarf palmetto (*Sabal minor*), American beautyberry (*Callicarpa americana*), and grape vines (*Vitis* spp.) in higher elevations, while wax myrtle (*Myrica cerifera*), dewberry (*Rubus* spp.), and various ferns are found in lower elevations. The vegetative community provides a good source of mast for numerous wildlife species and plentiful habitat. —

Cypress Pond

Cypress ponds are found in depressions throughout the uplands. The vegetative community consists of pond cypress (*Taxodium ascendens*), bald cypress, red maple, sweet gum, Virginia willow (*Itea virginica*), and buttonbush (*Cephalanthus occidentalis*).

Flatwoods

Flatwoods are often located in regions with unproductive soils with low water available to the vegetation. The plant community consists largely of longleaf pine (*Pinus palustris*) or slash pine (*P. elliottii*) with an understory consisting of saw palmetto (*Serenoa repens*), wax myrtle, and gallberry (*Ilex glabra*). The quality of this community for wildlife utilization appears to be poor as a result of historic fire suppression.

Sandhills

Xeric conditions brought on by sandy soils define the sparse vegetative community of the sandhills. The tree canopy consists of longleaf pine, sand pine (*Pinus clausa*), blackjack oak (*Q. incana*), and turkey oak (*Quercus laevis*) with wiregrass (*Aristida stricta*), palmettos, and various herbs in the understory.

Saltmarsh

The saltmarsh community occurs from the Gulf of Mexico in to the tidal creeks with the vegetative community transitioning from black needle rush (*Juncus roemerianus*) and smooth cordgrass (*Spartina alterniflora*) in the high salinity portions to sawgrass (*Cladium jamaicense*) in the fresher portions. Upland islands consist of red cedar, cabbage palm, and live oaks.

Scrub

The scrub community occurs on north-south strands occurring along prehistoric dunes. Scrub communities consist of sand pine, myrtle oak (*Q. myrtifolia*), and scrub live oak (*Q. geminata*).

Wet Prairie

Wet prairies occur scattered throughout the sandhills. They are dominated by marsh species including white-tops (*Dichromena colorata*), spikerushes (*Eleocharis* spp.), bog buttons (*Lachnocaulon anceps*), dahoon holly, American lotus (*Nelumbo lutea*), and spatterdock (*Nuphar lutea*).

Vegetation Impact Analysis

Monitoring stations are spread throughout the region at different distances from CNWA. Nonetheless, these measurements can be illustrative of baseline conditions at CNWA. The NO₂ concentration at St. Petersburg remains stable at approximately one-fifth of the national annual standard of 0.053 ppm (100 µg/m³). As a result of the Project, maximum NO₂ concentrations are projected to increase annually by only 0.0025 µg/m³ (Table 9-1), a small fraction of levels known to cause harm to the most sensitive vegetation (65 µg/m³ for 24 hours) as shown in Table 9-3. Currently, SO₂ at the Tampa-St. Petersburg-Clearwater sites are well below the annual national standard 0.03 ppm (80 µg/m³) (Table 3-5). A maximum SO₂ increase in 3-hour, 24-hour, and annual concentrations of 0.69, 0.16, and 0.0041 µg/m³, respectively (Table 9-1), as a result of TEC will not impact the most sensitive vegetation with tolerances of 131 µg/m³ for 8 hours and 13 µg/m³ for chronic exposures (Table 9-4). The SO₂ concentration increase as a result of the Project will produce a negligible increase in concentrations with respect to vegetative impacts.

PM₁₀ concentrations in the St. Petersburg-Tampa-Clearwater area remain well below the annual average Florida AAQS standard of 50 µg/m³. The impact from the small maximum annual and 24-hour PM₁₀ increases of 0.0053 and 0.17 µg/m³, respectively (Table 9-1), as a result of the TEC Project, are negligible with regard to ecosystem impacts within the CNWA.

Typical Wildlife

The diverse array of communities and the close association between wetlands and uplands allows for a wide array of wildlife species. Many species of wildlife that are endangered, threatened, or species of special concern are present in the CNWA including the Florida black bear, Florida mouse, gopher tortoise, Eastern indigo snake, Florida gopher frog, American alligator, Florida pine snake, and potentially bald eagles. The heterogeneous composition of the aquatic communities and range of salinities allows for a large diversity of fish species typical of this region of Florida.

Whooping crane populations have recently been established to winter in the CNWA. In addition, along their migratory pathway, they have been known to occur near the TEC Site. This is a sensitive species brought back from the brink of extinction. On their wintering grounds, the whooping crane prefers a habitat within estuarine marshes, shallow bays, and salt tidal flats and can be found within freshwater wetlands along their migration path. They prefer to feed on crabs, shrimps, clams, snails, frogs, snakes, grasshoppers, larval and nymph forms of flies, beetles, water bugs, birds, and small mammals. In addition, they have been known to eat more than 58 species of fish.

Wildlife Impact Evaluation

Air pollutant concentrations in the project vicinity are projected to be well below NAAQS standards (Table 3-5) and minimum threshold concentrations (Table 9-5), below which no wildlife acute toxicity is expected to occur. Most air pollution effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed above, minimal impacts to vegetation are expected to occur as a result of the low emissions increases in CNWR. Therefore, no adverse impacts to wildlife are expected due to TEC.

Due to the fact that the cranes are a carnivorous species, predominantly feeding in wetlands, (where mercury methylation is accelerated) there is a potential for biomagnification of mercury. Mercury deposition is monitored at CNWR as part of the Mercury Deposition Program (MDP). Annual average wet deposition values of mercury at the MDP monitoring station range from 0.3 to 0.5 kg/ha/yr (Figure 9-4). These values are

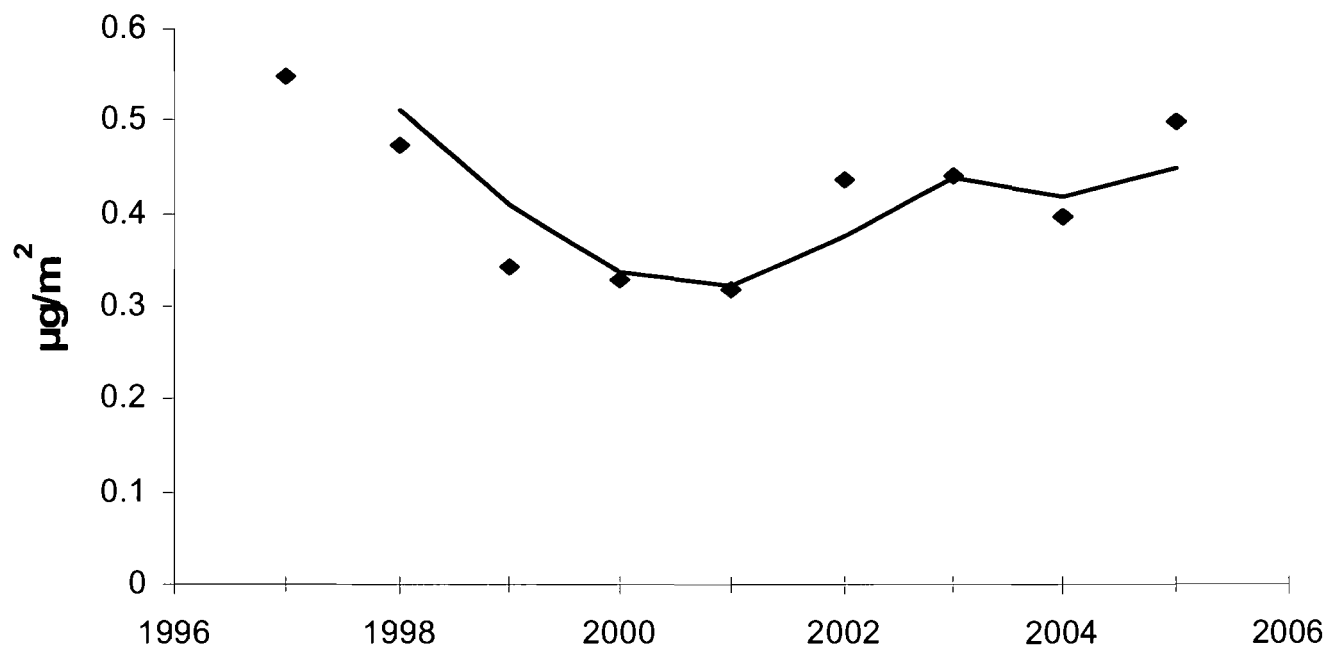


FIGURE 9-4.

MDP WET DEPOSITION VALUES AND MOVING AVERAGE
TRENDLINE FOR MERCURY WITHIN THE CNWA

Source: ECT, 2005.



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within the lower end of the range of reported background mercury deposition rates of 0.5 and 1 $\mu\text{g m}^{-2} \text{ yr}^{-1}$ (Bindler, 2003). No studies have been found that determine the impact of mercury deposition on the CNWA ecosystem, but these deposition levels are roughly equivalent to deposition occurring in ONWA, where mercury has been found at high levels in fish tissue, as discussed previously.

The mercury deposition rate as a result of this Project (0.0736 $\mu\text{g/m}^2/\text{yr}$ maxima) (Table 9-2) in the vicinity of TEC is an order of magnitude lower than conservative natural background deposition estimates (0.5 to 1 $\mu\text{g/m}^2/\text{yr}$) (Bindler 2003) and existing deposition (shown in Figure 9-4). It is safe to assume that mercury deposition at the distant CNWR will be much lower than the small amount emitted in the vicinity of TEC, where it was deemed that no wildlife impacts are projected to occur. Therefore, it is unlikely that whooping cranes will be significantly affected by mercury along their migratory pathway or in their wintering grounds in the CNWA as a result of this Project.

Migratory birds spending time in freshwater wetlands can be affected by acidification (Longcore, Ross, and Fischer, 1987). Reproductive success of birds with a variety of feeding habits has declined as a result of acidification-induced reductions in food abundance (Blancher and McAuley, 1987). Due to the low emissions discussed throughout these sections, which have been shown to be below levels causing significant acidity, it is unlikely that the whooping crane will be affected.

Soil Characteristics

Soil types within the CNWA are listed in the conceptual management plan (FWS, 2001). NRCS/USDA soil surveys were utilized to compile a table of soil pH (Table 9-10) and relevant soil chemical properties for all the soils listed (Table 9-11). Soils found in the CNWA range from very poorly drained organic soils (Aripeka-Okeelanta-Lauderhill and Okeelanta-Terra Ceia) in the freshwater wetlands and saltwater marshes to excessively drained sandy soils in the sandhills (Candler fine sand). The dominant soils are histosols and the psamment subgroup of the series entisols.

Table 9-10. Soil pHs for the Soils Found in the CNWA

Soil	Depth (inches)	Soil Reaction (pH)
Adamsville-fine sand	0 to 80	4.5 to 7.8
Anclote fine sand	0 to 80	5.1 to 8.4
Aripeka fine sand	0 to 13	5.6 to 7.8
	13 to 21	6.6 to 8.4
Aripeka - Okeelanta - Lauderdale		
Okeelanta	0 to 27	5.1 to 6.5
	27 to 60	5.1 to 7.3
Lauderhill	0 to 80	6.1 to 8.4
Astatula fine sand	0 to 80	4.5 to 6.5
Basinger fine sand	0 to 8	3.6 to 8.4
	8 to 60	3.6 to 7.3
Basinger fine sand, depressional	0 to 80	3.6 to 7.3
Candler fine sand	0 to 80	4.5 to 6.0
EauGallie fine sand	0 to 25	4.5 to 6.0
	25 to 33	4.5 to 6.5
	33 to 57	5.1 to 7.8
	57 to 63	5.1 to 7.8
Homosassa mucky fine sandy loam	0 to 80	6.1 to 7.8
Lacoochee fine sandy loam	0 to 8	7.9 to 8.4
	8 to 13	6.6 to 8.4
Myakka fine sand	0 to 80	3.6 to 6.5
Okeelanta - Terra Ceia		
Okeelanta	0 to 27	4.5 to 7.8
	27 to 60	5.1 to 7.8
Terra Ceia	0 to 80	5.6 to 8.4
Paola fine sand	0 to 80	3.6 to 7.3
Pomello fine sand	0 to 80	4.5 to 6.0
Tavares fine sand	0 to 80	4.5 to 6.0
Weekiwachee muck	0 to 80	6.1 to 7.8
Weekiwachee - Homosassa	0 to 80	6.1 to 7.8

Source: USDA, NRCS soil surveys of Citrus County, 1988 and Hernando County, 1977.

Table 9-11. Chemical Properties of the Soils within the CNWA

Soil	Depth (cm)	Horizon	Cadmium	Magnesium	Sodium	Potassium	CEC	Base Saturation
Adamsville-fine sand	0 to 18	Ap	1.19	0.27	0.02	0.13	5.04	32
	18 to 51	C1	0.2	0.07	0.01	0.03	1.36	23
	51 to 99	C2	0.12	0.05	0.01	0.01	0.72	26
	99 to 152	C3	0.04	0.04	0.02	0	0.4	25
	152 to 203	C3	0.06	0.02	0.01	0	0.24	38
Aripeka fine sand	0 to 8	A1	3.1	1.6	0	0.1	7.8	62
	8 to 13	A2	1.2	0.6	0	0.1	4	48
	13 to 25	B21	0.4	0.3	0.1	0	1.8	44
	25 to 33	B22	1.4	0.5	0.1	0	3	67
	33 to 38	B23t	7.7	1.5	0.8	0.2	14.1	72
	38 to 53	B24t	10.8	1	1.6	0.2	15.8	86
Astatula fine sand	0 to 13	A	0.11	0.04	0.02	0.02	2.4	8
	13 to 46	C1	0.03	0.01	0.02	0.01	1.74	4
	46 to 119	C2	0.02	0.01	0.01	0	0.78	5
	119 to 203	C3	0.02	0.01	0.01	0	0.68	6
Candler fine sand	0 to 10	A	0.18	0.05	0.01	0.01	3.02	8
	10 to 36	E1	0.03	0.02	0.01	0.01	1.5	5
	36 to 89	E2	0.03	0.02	0.01	0	0.61	10
	89 to 132	E3	0.01	0.02	0.01	0	0.45	9
	132 to 183	E4	0.02	0.02	0.01	0	0.24	21
	183 to 203	E/Bt	0.02	0.03	0.01	0	0.4	15

Table 9-11. Chemical Properties of the Soils within the CNWA (Continued, Page 2 of 2)

Soil	Depth (cm)	Horizon	Cadmium	Magnesium	Sodium	Potassium	CEC	Base Saturation
EauGallie fine sand	0 to 8	A1	4.8	3.36	0.12	0.13	19.91	42
	8 to 25	A2	0.51	0.56	0.04	0.03	4.19	27
	25 to 56	E	0.05	0.03	0.02	0	0.55	18
	56 to 114	Bh1	0.15	0.18	0.07	0	19.3	2
	114 to 135	Bh2	0.24	0.05	0.05	0	9.57	4
	135 to 173	Btg1	2.53	0.48	0.11	0.14	12.66	26
	173 to 203	Btg2	3.8	0.48	0.09	0.14	11.87	38
Myakka fine sand	0 to 10	A	2.46	2.33	0.11	0.05	14.64	34
	10 to 25	E1	1.13	0.89	0.08	0.02	6.75	31
	25 to 68	E2	0.05	0.03	0.02	0	0.18	56
	68 to 107	Bh1	0.12	0.04	0.05	0	14.46	1
	107 to 140	Bh2	0.24	0.04	0.05	0	10.99	3
	140 to 170	BC	0.49	0.05	0.03	0	5.94	10
	170 to 203	Bh'	4.35	0.08	0.08	0.01	9.23	49
Tavares fine sand	0 to 8	A	0.64	0.16	0.01	0.03	3.16	27
	8 to 56	C1	0.04	0.02	0.01	0.01	1.35	6
	56 to 104	C1	0.02	0.01	0	0	0.96	3
	104 to 160	C2	0.03	0.02	0.02	0	0.37	19
	160 to 203	C3	0.02	0.01	0.01	0	0.14	29

Source: USDA, NRCS soil surveys of Citrus County, 1988 and Hernando County, 1977.

Soils Impacts Evaluation

Dominant soil types (histosols, psamment entisols) have a high sulfate adsorption capacity, increasing buffering to changes in pH (Johnson and Reuss, 1984). Base saturation of the soils of the CNWA tends to be high, even in surface horizons, further indicating a strong buffering capacity. The Astatula soil has a low base saturation, but it comprises only 0.15 percent of the refuge.

Soil acidification and eutrophication and other effects can occur as a result of atmospheric deposition of NO_x and SO_x. Atmospheric deposition is monitored at the CNWA as part of the NADP. Annual averages for wet deposition of nitrate and sulfate are shown in Figures 9-5 and 9-6, respectively. NADP monitoring of average annual nitrate wet deposition values range between approximately 7 to 10 kg/ha/yr (Figure 9-5). These deposition values are below the threshold (15 to 20 hg/ha/yr) where eutrophication has been observed in calcareous forests (Thimonier *et al.*, 1994). Maximum atmospheric total deposition of nitrogen is projected to increase by 0.0011 kg/ha/yr as a result of the Project (Table 9-2), which would cause no measurable eutrophication of the CNWA. Average annual sulfite wet deposition values range between approximately 13 to 16 kg/ha/yr (Figure 9-6). The dominant soil types of the refuge are well buffered to sulfate deposition. Regardless, sulfur total atmospheric deposition will only increase at a maximum of 0.0048 kg/ha/yr within the refuge as a result of the Project (Table 9-2).

9.2.5.3 St. Marks NWA

Vegetation Types

The St. Marks National Wilderness Area (SMNWA) contains six dominant forested communities including longleaf pine-turkey oak sandhill communities, scrubby flatwoods, mesic hammocks, wet flatwoods, and hydric hammocks (USFWS, 2006).

Longleaf Pine-Turkey Oak Sandhill Community

Longleaf pine (*Pinus palustris*) dominates the vegetative composition of this vegetative community. Other species found include turkey oak (*Quercus laevis*) and bluejack oak (*Q. marilandica*) in the canopy with an understory dominated by wiregrass (*Aristida*

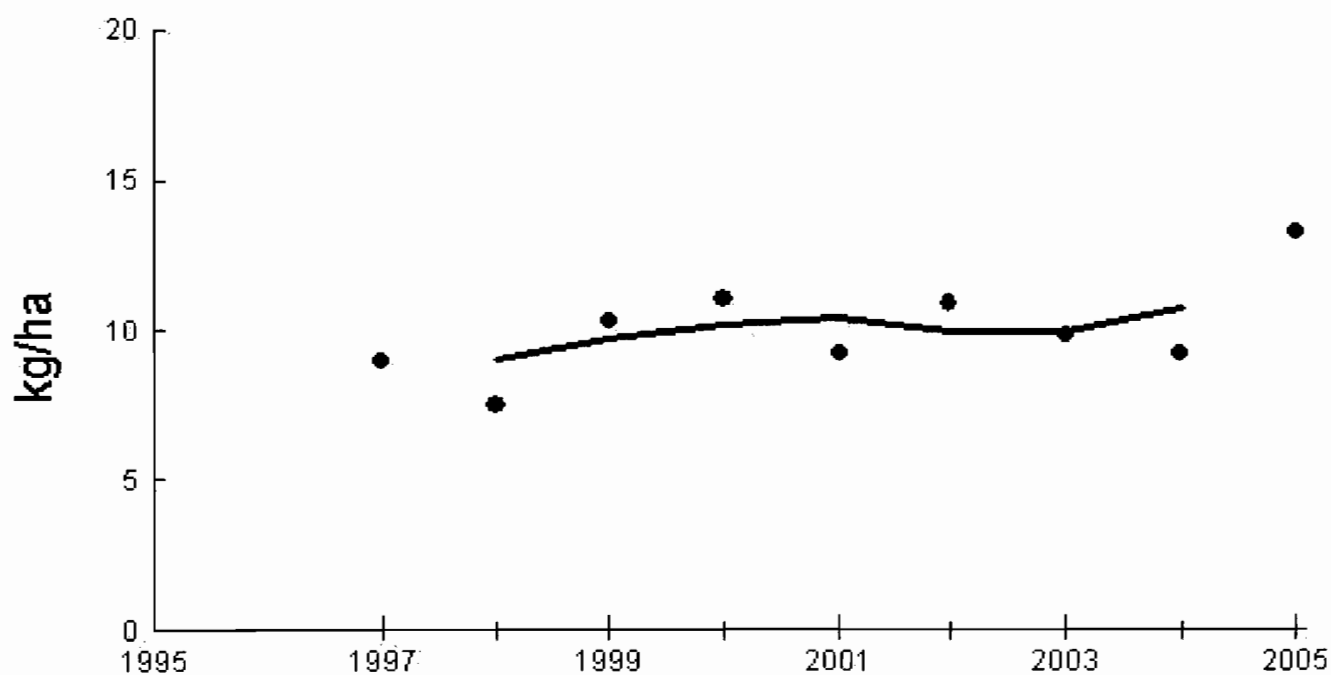


FIGURE 9-5.
NADP ANNUAL WET DEPOSITION VALUES AND
3-YEAR WEIGHTED AVERAGE TRENDLINE FOR
NITRATE WITHIN THE CNWA

Source: ECT, 2005.



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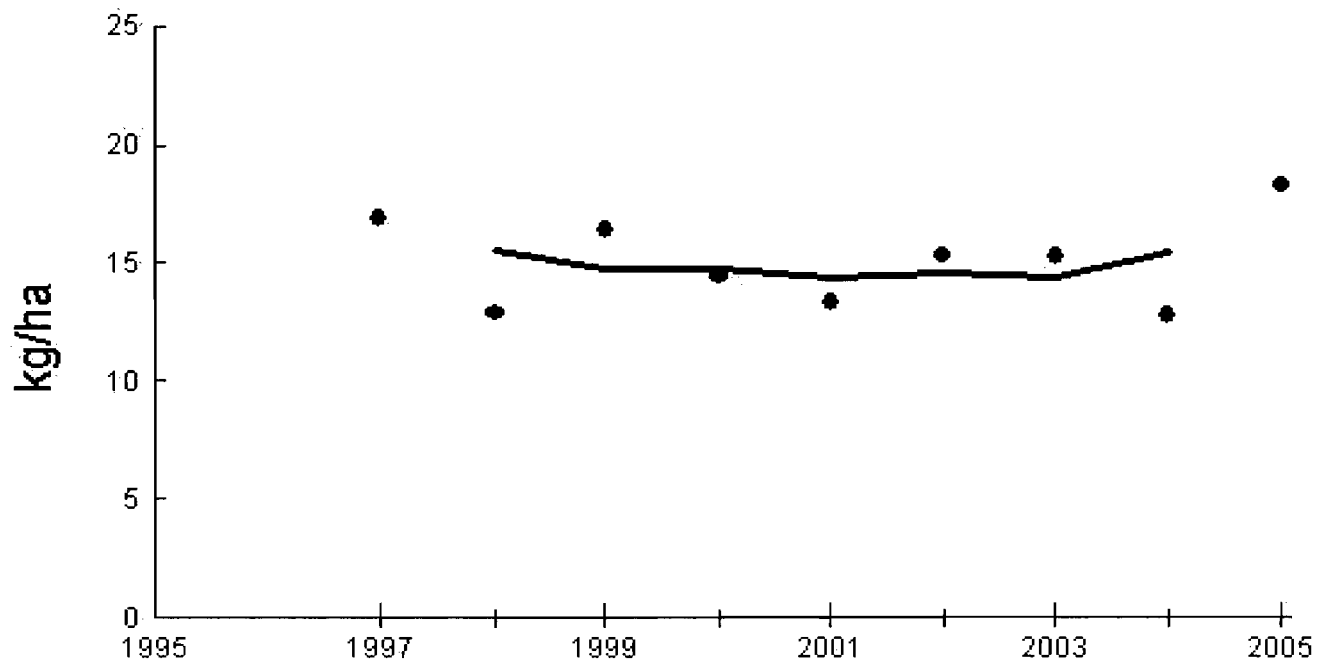


FIGURE 9-6.
NADP WET DEPOSITION VALUES AND 3-YEAR
WEIGHTED AVERAGE TRENDLINE FOR SO₃
WITHIN THE CNWA

Source: ECT, 2005.

stricta) accompanied by narrow-leaf aster (*Lonactis linariifolius*), spurge nettle (*Cnidolscolus stimulosus*), deerberry (*Vaccinium stamineum*), and lupine (*Lupinus* spp.).

Scrubby Flatwoods

Scrubby flatwoods have sparsely populated slash pine and longleaf pine, with an understory of saw palmetto (*Serenoa repens*), myrtle oak (*Quercus myrtifolia*), sand-live oak (*Quercus geminata*), prickly pear cactus (*Opuntia* spp.), reindeer moss, and greenbrier (*Smilax* spp.).

Mesic Flatwoods

Nearly one-third of the forestland of the refuge is classified as mesic flatwoods. The canopy is dominated by longleaf pine, loblolly pine, and pond pines near the coast. The understory generally consists of gallberry (*Ilex glabra*), saw palmetto, wiregrass, lowbush blueberries (*Vaccinium angustifolium*), staggerbush (*Lyonia mariana*), huckleberry (*Gaylussacia* spp.), sweet pepperbush (*Clethra alnifolia*), and dangleberry (*Gaylussacia frondosa*).

Mesic Hammock

Mesic hammocks are defined by moderately dense communities dominated by mixed hardwoods or pine-hardwoods. The canopy contains a mixture of overstory and understory trees including live oak (*Quercus virginiana*), sweetgum (*Liquidambar styraciflua*), laurel oak (*Quercus hemisphaerica*), water oak (*Quercus nigra*), redbay (*Persea borbonia*), wax myrtle (*Myrica cerifera*), persimmon (*Diospyros virginiana*), pignut hickory (*Carya glabra*), yaupon holly (*Ilex vomitoria*), and flowering dogwood (*Cornus florida*). The sparse understory consists of spike grass (*Distichlus spicata*), American beautyberry (*Callicarpa americana*), saw palmetto, poison ivy (*Toxicodendrum radicans*), gallberry, muscadine (*Vitis* spp.), Virginia creeper (*Parthenocissus quinquefolia*), and witch hazel (*Hamamelis* spp.).

Wet Flatwoods

This vegetative community can be further subdivided into two distinct communities—longleaf pine-wiregrass and slash pine-sedge. The overstory of the longleaf pine-

wiregrass community is open containing low-density canopies of longleaf pine and some slash pine. The understory is dominated by wiregrass but contains a diverse variety of vegetation including St. John's wort (*Hypericum* spp.), club moss (*Lycopodium* sp.), sedges, yellow-eyed grass (*Xyris* spp.), various orchids, dwarf wax myrtle (*Myrica pusilla*), goldcrest, and Florida dropseed (*Sporobolus floridana*). The slash pine-sedge wet flatwoods community contains a slash pine canopy with some pond cypress and a ground cover dominated by sawgrass (*Cladium jaimacense*) and needlerush (*Juncus* spp.).

Hydric Hammock

Hydric hammocks differ from the mesic hammocks in that it is dominated by cabbage palmetto (*Sabal palmetto*), diamond-leaf oak (*Quercus laurifolia*), red maple (*Acer rubrum*), sweet bay (*Magnolia virginiana*), swamp ash (*Fraxinus nigra*), and sawgrass. This vegetation is indicative of the wet conditions.

In addition the refuge contains four major wetland types. Wetlands comprise approximately 70 percent of the total acreage of the refuge. Seven rivers and numerous creeks traverse the refuge and drain through marshes into the Apalachee Bay estuary. Numerous forested swamps and manmade impoundments are present throughout the refuge. The four major wetland types found on the refuge are forested swamps, freshwater marshes, saltwater marshes, and estuarine ecosystems.

Forested Swamps

Forested swamps consist of a mixed variety of conifers and hardwoods. Within lower elevation sites cypress is dominant with pines, cedars (*Juniperus virginiana*), gums (*Tupelo* spp.), oaks, palms, and willows (*Salix* spp.) found in and around these habitats.

Freshwater Marshes

Freshwater marshes are dominated by herbaceous species with little canopy cover. These marsh habitats attract a variety of waterfowl, wading birds, shellfish, alligators, and raptors and provide nursery grounds for a variety of fish. They often are in transition zones between saltwater marshes and uplands. The vegetation changes depending on the salin-

ity boundary with sawgrass and other marsh species predominantly occurring in these freshwater habitats.

Saltwater Marshes

Saltwater marshes are located between Apalachee Bay and the uplands. Saltwater marshes are a productive community used by a variety of juvenile fish and many shellfish. The vegetation consists predominantly of cordgrass (*Spartina* spp.), with some needlerush and sawgrass.

Estuarine Ecosystems

This ecosystem occurs offshore in Apalachee Bay beyond the saltwater marsh communities. The vegetation of this ecosystem predominantly consists of seagrass. The seagrass beds provide an important habitat for many species of fish, oysters, and water birds.

Vegetation Impact Evaluation

The closest EPA monitoring station to SMNWA for NO₂ is located in Pensacola, Florida, near an urban area. The NO₂ concentration at this station remains well below the annual average NAAQS of 0.053 ppm (100 µg/m³) (Table 3-5). A small maximum annual increase of NO_x by 0.0209 µg/m³ (Table 9-1) as a result of TEC will maintain the atmospheric concentration well below vegetative injury thresholds of 65 µg/m³ for 24 hours as shown in Table 9-3. The nearest station to SMNWA for SO₂ monitoring is in Hamilton County. The annual average concentrations of SO₂ at this monitoring station are currently well below the national standard 0.03 ppm (80 µg/m³) (Table 3-5). An increase in 3-hour, 24-hour, and annual SO₂ concentrations of 2.41, 0.67, and 0.0263 µg/m³, respectively (Table 9-1), as the result of TEC will not increase current concentrations near plant injury thresholds of the most sensitive vegetative species with tolerances of 131 µg/m³ for 8 hours and 13 µg/m³ for chronic exposures (Table 9-4). Therefore, no vegetation is expected to be impacted in SMNWA as a result of the TEC.

The closest PM₁₀ monitoring station to SMNWA is in Tallahassee. The PM₁₀ levels within this urban area have never exceeded the state annual standard (50 µg/m³) (Table 3-5). Maximum PM₁₀ elevation at the SMNWA as a result of TEC is modeled to be 0.3 and

0.0216 $\mu\text{g}/\text{m}^3$ for 24-hours and annually (Table 9-1). These increases are expected to have no significant impact to vegetation on the refuge.

Typical Wildlife

With 278 species documented, there is an immense diversity of birds that permanently or periodically occupy the SMNWA. These include waterfowl like the teal, pintail, widgeon, mallard, and many other ducks found in impoundments. Shorebirds, waterbirds, and marshbirds present in the refuge include black, king, and yellow rails; piping plover; little blue heron; American avocet; lesser yellowlegs; and Wilson's snipe. There are many avian species present on the refuge that are listed under provisions of the Endangered Species Act, including the red-cockaded woodpecker, wood stork, bald eagle, and piping plover. State listed species include the least tern and the southeastern American kestrel. In addition, swallow-tailed kites have been witnessed in SMNWA.

There are 50 species of mammal that have been observed in SMNWA. These include the least shrew, Seminole bat, golden mouse, rice rat, fox squirrel, grey fox, river otter, bobcat, black bear, coyote, and manatee.

Within the SMNWA, there are 40 species of amphibians (21 frogs and 19 salamanders) including the barking tree frog, river frog, gopher frog, striped newt, flatwoods salamander, and one-toed amphiuma. There are currently 68 species of reptiles documented on the refuge, including 13 species of lizards, 36 species of snakes, and 18 species of turtles. Reptiles present on this property include the American alligator, mole skink, island glass lizard, pine snake, eastern indigo snake, southern hognose snake, blue-striped garter snake, blue-striped ribbon snake, alligator snapping turtle, spotted turtle, gopher tortoise, Kemp's ridley sea turtle, and diamondback terrapins.

There are some important and unique invertebrates present in SMNWA in Big Blue Springs including the Blue Springs Cave Crayfish, Hobb's cave amphipod, and Florida cave amphipod. In addition, migrating Monarch butterflies are seasonally present.

Fish documented at SMNWA currently include 145 species. The high diversity of fresh-water and estuarine habitats provides for a large diversity of fish.

Endangered species found in SMNWA include the red-cockaded woodpecker, wood stork, Florida manatee, Ochlocknee mocassinshell, Kemp's Ridley sea turtle, and the green sea turtle. Threatened species include the bald eagle, flatwoods salamander, piping plover, loggerhead sea turtle, eastern indigo snake, purple bankclimber, and the Gulf sturgeon.

Wildlife Impact Evaluation

Air pollutant concentrations in the project vicinity are projected to be well below NAAQS standards and minimum threshold concentrations (Table 9-5), below which no wildlife acute toxicity is expected to occur. Most air pollution effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed above, minimal impacts to vegetation are expected to occur as a result of the low emissions increases due to TEC in SMNWA. Therefore, no adverse impacts to wildlife are expected.

Soil Characteristics

The soils of the SMNWA as indicated in the comprehensive conservation plan are Leon-Scranton-Rutledge, Tooles-Nutall-Chaires, Lakeland-Ortega-Alpin, Ridgewood-Ortega-Rutledge, and Bayvi-Isles-Estero (FWS, 2006). Soil pH values are shown in Table 9-12, and relevant soil chemical parameters are shown in Table 9-13, as compiled from soil surveys. The soils found on SMNWA are spodosols, mollisols, alfisols, and the psamment subgroup of entisols.

Soils Impact Evaluation

As mentioned previously, spodosols and the psamment subgroup of entisols are buffered to pH changes as a result of high sulfate adsorption capacities. Base saturation of the soils is generally quite high, with the exception of the Lakeland and Alpin soils. These soils have a high cation exchange capacity which will allow them to be buffered to acid causing H⁺ ions.

Table 9-12. Soil pHs for the Soils Found on SMNWA

Soil	Depth (inches)	Soil Reaction
Bayvi-Isles-Estero		
Bayvi	0 to 80	6.1 to 8.4
Isles	0 to 35	5.7 to 7.8
	35	5.6 to 8.4
Estero	0 to 34	6.6 to 8.4
	34 to 80	4.5 to 8.4
Lakeland-Ortega-Alpin		
Lakeland	0 to 80	4.5 to 6.0
Ortega	0 to 80	3.6 to 6.5
Alpin	0 to 80	4.5 to 6.5
Leon-Scranton-Rutledge		
Leon	0 to 80	3.6 to 5.5
Scranton	0 to 7	4.5 to 6.5
	7 to 80	4.5 to 6.0
Rutledge	0 to 80	3.6 to 5.5
Ridgewood-Ortega-Rutledge		
Ridgewood	0 to 4	3.6 to 7.3
	4 to 80	4.5 to 7.3
Ortega	0 to 80	3.6 to 6.5
Rutledge	0 to 80	3.6 to 5.5
Tooles-Nutall-Chaires		
Tooles	0 to 26	4.5 to 7.3
	26 to 50	6.6 to 8.4
Nutall	0 to 10	4.5 to 7.3
	10 to 80	6.6 to 8.4
Chaires	0 to 33	3.6 to 5.5
	33 to 80	4.5 to 7.3

Source: USDA, NRCS soil surveys for Jefferson County, 1989; Taylor County, 2000; and Wakulla County, 1991.

Table 9-13. Chemical Properties of the Soils within the SMNWA

Soil	Depth (cm)	Horizon	Cadmium	Magnesium	Sodium	Potassium	CEC	Base Saturation
<u>Lakeland-Ortega-Alpin</u>								
Lakeland	0 to 20	Ap	0.22	0.06	0.03	0.02	11.27	3
	20 to 41	C1	0.04	0.02	0.02	0.01	6.98	1
	41 to 56	C2	0.06	0.04	0.02	0.01	5.75	2
	56 to 102	C3	0.09	0.05	0.02	0.01	4.65	4
	102 to 203	C4	0.13	0.09	0.02	0.01	3.1	8
Alpin	0 to 10	Ap	0.4	0.08	0.03	0.01	6.1	9
	10 to 51	E1	0.03	0.02	0.02	0	3.15	2
	51 to 102	E2	0.04	0.03	0.12	0	2.04	9
	102 to 119	E3	0.04	0.03	0.01	0	1.4	6
	119 to 203	E/B	0.04	0.04	0.01	0	1.52	6
<u>Leon-Scranton-Rutledge</u>								
Leon	0 to 13	Ap	1.85	0.29	0.06	0.04	16.37	14
	13 to 28	E1	0.53	0.06	0.02	0.01	6.07	10
	28 to 53	E2	0.12	0.03	0.01	0	3.42	6
	53 to 64	Bh1	0.35	0.05	0.03	0	13.3	3
	64 to 135	Bh2	0.33	0.02	0.02	0.01	12.55	3
	135 to 145	E'	0.35	0.02	0.05	0.01	12.36	3
	145 to 203	Bh'	0.13	0.01	0.02	0	12.41	1
<u>Ridgewood-Ortega-Rutledge</u>								
Ridgewood	0 to 18	Ap	0.38	0.08	0.02	0.01	2.34	21
	18 to 41	C1	0.06	0.02	0.04	0.01	1.65	8
	41 to 91	C2	0.03	0.02	0.02	0.01	0.75	11
	91 to 235	C3	0.01	0	0.01	0	0.22	9
	135 to 203	C4	0.06	0	0	0	0.29	21

Table 9-13. Chemical Properties of the Soils within the SMNWA (Continued, Page 2 of 2)

Soil	Depth (cm)	Horizon	Cadmium	Magnesium	Sodium	Potassium	CEC	Base Saturation
<u>Tooles-Nutall-Chaires</u>							7.7	
Tooles	0 to 20	Ap	0.7	0.04	0	0	2.49	30
	20 to 58	Bw1	0.46	0.03	0	0	1.13	43
	58 to 89	Bw2	0.6	0.02	0	0	0.92	67
	89 to 117	Btg	24	0.24	0.02	0.11	27.01	90
Nutall	0 to 10	Ap	6.16	0.6	0.08	0.08	21.17	33
	10 to 23	A/E	2.5	0.04	0.03	0.01	4.36	59
	23 to 33	E1	0.52	0.02	0.03	0.01	1.11	52
	33 to 43	E2	0.63	0.02	0.02	0	1.06	63
	43 to 76	Btg	24.37	0.24	0.1	0.25	30.16	83
Chaires	0 to 15	Ap	0.82	0.41	0.04	0.04	10.42	13
	15 to 51	E	0.08	0.01	0.01	0	4.16	2
	51 to 66	Bh1	0.04	0.06	0.03	0.01	19.09	1
	66 to 76	Bh2	0.03	0.02	0.02	0.01	13.42	1
	76 to 132	E'	0.05	0.02	0.01	0.01	10.29	1
	132 to 203	Btg	7.75	5.35	0.05	0.06	20.28	65

Source: USDA, NRCS soil surveys for Jefferson County, 1989; Taylor County, 2000; and Wakulla County, 1991.

An increase in nitrogen and sulfur deposition of 0.0152 and 0.0354 kg/ha/yr, respectively (Table 9-2), is expected as a result of the Project. Thimonier *et al.* (1994) found a critical threshold where eutrophication occurred in calcareous forests above atmospheric deposition values of 15 to 20 kg/ha/yr. The fact that the increased deposition at SMNWA is several orders of magnitude below this critical threshold indicates there is no potential for TEC to exacerbate eutrophication. In addition, no other soil impacts are expected to occur.

9.2.5.4 Wolf Island NWA

Vegetation Types

Wolf Island National Wilderness Area (WINWA) consists of beach and sand dune vegetative communities on the coast, with salt marsh, small marsh hammocks, tidal creeks, and 300 acres (6.6 percent) of uplands on the interior portion.

Beach vegetation consists of sea rocket (*Cakile* spp.), beach hogwort (*Croton punctatus*), beach sandspur (*Cenchrus tribuloides*), salt meadow cordgrass (*Spartina patens*), salt wort (*Salsola kali*), sea-purslane (*Sesuvium* spp.), beach-spurge (*Euphorbia polygonifolia*) and seashore elder (*Iva imbricata*). Vegetation found on the foredune includes sea oats, sea beach panic grass, railroad vine (*Ipomoea stolonifera*), beach pennywort (*Hydrocotyle bonariensis*), and Spanish-bayonet (*Yucca* spp.). Salt tolerant species are present on the crest of the foredunes and the foreslope. The species present includes little bluestem (*Andropogon scoparius*), prickly pear (*Opuntia* spp.), seaside goldenrod (*Solidago sempervirens*), beach primrose (*Oenothera humifusa*), juniper (*Juniperus virginiana*), yaupon holly (*Ilex vomitoria*), wax myrtle (*Myrica cerifera*), and live oak (*Quercus virginiana*).

Upland vegetation found in the more stable areas behind the dune consists of more shrubs and trees. Growth of this vegetation is often limited by wind and salt-spray. Species found in this region include live oak, red bay (*Persea borbonia*), wax myrtle, juniper, yaupon, cabbage palm (*Sabal palmetto*), saw palmetto (*Serenoa repens*), and groundsel-bush (*Baccharis halimifolia*).

More than 75 percent of the WINWA's 5,126 acres are composed of saltwater marshes. The salt marsh is dominated by salt marsh cord grass (*Spartina alterniflora*) with sea ox-eye (*Borrchia arborescens*), needle grass, and glasswort (*Salicornia* spp.).

Sand blackberry (*Rubus cuneifolius*) and smooth cordgrass (*Spartina alterniflora*) are both known to be sensitive to ozone, and they are present on WINWA.

Vegetation Impact Evaluation

SO₂ concentrations at this monitoring station are well below the national standards for annual averages of 0.03 ppm (80 µg/m³) (Table 3-5). In addition, annual averages of PM₁₀ at this monitoring station have never exceeded the annual AAQS 50 µg/m³. Modeled SO₂ 3-hour, 24-hour, and annual concentrations are projected to increase by 0.33, 0.10, and 0.0036 µg/m³, respectively, at a maximum as a result of the Project (Table 9-1). These concentrations are miniscule and will provide no harm to even the most sensitive vegetation, with thresholds of 131 µg/m³ for 8 hours and 13 for chronic exposures (Table 9-4). PM₁₀ concentrations are projected to increase by 0.07 µg/m³ and 0.004 for averaging periods of 24-hours and annually (Table 9-1), which will have a negligible impact on the ecosystems of Wolf Island. Although there is no NO_x monitoring nearby, the projected increase of 0.0023 µg/m³ as a result of TEC (Table 9-1) is orders of magnitude lower than generalized plant injury thresholds of 65 µg/m³ (Table 9-3). Therefore, no adverse effects on the vegetation are expected as a result of the TEC.

Typical Wildlife

The wildlife found on the refuge is typical of barrier islands of the southeast including brown pelicans, loggerhead sea turtles, diamondback terrapins, and various shore birds and marsh birds. Migratory waterfowl found wintering on the refuge include scaup, scoters, black ducks, mergansers, and buffleheads. In addition, fish and shellfish are common in the tidal creeks and coastal areas. Air pollution impacts on wildlife are mostly manifested indirectly via direct impacts to the vegetation and soils and for aquatic species, modifications to water chemistry. As is discussed in the Vegetation and Soil Impacts sections, the small increases in atmospheric pollutants within WINWA, will not ad-

versely these ecosystem components. As a result it is apparent that wildlife will not be adversely impacted.

Wildlife Impact Evaluation

Air pollutant concentrations in the project vicinity are projected to be below NAAQS standards and minimum threshold concentrations (Table 9-5), below which no wildlife acute toxicity is expected to occur. Most air pollution effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed above, minimal impacts to vegetation are expected to occur as a result of the low emissions increases in WINWA. Therefore, no adverse impacts to wildlife are expected.

Soil Characteristics

Soils have been historically mapped for this region with limited descriptions (Byrd, 1961). Soil reaction (pH) values are listed in Table 9-14. Upland soils consist predominantly of low pH, porous sand from recent deposition of marine materials, with a distinct surface horizon containing elevated amounts of organic matter. These soils are classified as being moderately to severely sensitive to leaching. This tends to indicate that these soils are sensitive to the effects of acid deposition. The soil series found in the uplands include Blanton, Galestown, Klej, Lakeland, and Palm Beach. More poorly drained sites consist of the following soil series: Leon, Ona, Plummer, Rutlege, and St. Johns. These soils are predominantly acidic, with the exception of alkaline oyster shell islands. In addition, there are large areas of salt marsh soils. These soils are dominated by tidal influences and tend to be high in organic matter content.

Soils Impact Evaluation

Atmospheric deposition of nitrate and sulfate has been monitored in nearby Sapelo Island. Available NADP monitoring values for annual average wet deposition of nitrate and sulfite have measured values at 8 and 11 kg/ha/yr, respectively. Atmospheric deposition of nitrogen and sulfur as a result of TEC is modeled to be a maximum of 0.0033 and 0.0063 kg/ha/yr (Table 9-2). These values are so low that it is highly unlikely that any noticeable impact to the soils will occur as a result of the Project's emissions. Mercury

Table 9-14. Soil pHs for the Soils Found on WINWA

Soil	Depth (inches)	Soil Reaction
Leon	0 to 80	4.0 to 5.0
Rutlege	0 to 80	4.0 to 5.0
Ona	0 to 80	4.0 to 5.5
Plummer	0 to 80	4.0 to 5.5
		4.0 to 5.0
St Johns	0 to 80	4.0 to 5.0
Blanton	0 to 80	4.5 to 6.0
Galestown	0 to 80	4.5 to 5.5
Klej	0 to 80	4.5 to 6.0
Lakeland	0 to 80	4.5 to 6.0
Palm Beach	0 to 80	7.0 to 8.5

Source: USDA, NRCS soil surveys for McIntosh County, GA. 1961.

deposition is monitored at nearby ONWA. These values are listed and discussed previously in Section 9.2.5.1.

9.2.5.5 Bradwell Bay NWA

Typical Vegetation and Wildlife

Bradwell Bay is a wilderness area that is part of the Apalachicola National Forest. Bradwell Bay consists predominantly of deepwater swamps containing shrub thickets of titi with clumps of blackgum, water oak, sweetbay, sweetgum, red maple, black willow, common alder, and cypress. Islands of longleaf pine, slash pine, water oak, wire grass, fetterbush lyonia, saw palmetto, waxmyrtle, and gallberry are present around the perimeter. White-tailed deer, black bears, and alligators are present in and around the swamps.

Vegetation and Wildlife Impact Evaluation

PM₁₀ is monitored in nearby urban Tallahassee. PM₁₀ concentrations are well below the Florida annual AAQS standard (50 µg/m³) (Table 3-5). The expected maximum 24-hour and annual increase in PM₁₀ concentration of 0.20 and 0.0119 µg/m³, respectively, would not measurably raise concentrations in the area (Table 9-1). Projected NO_x increases of 0.0093 µg/m³ are orders of magnitude lower than generalized plant injury concentrations of 65 µg/m³ for 24 hours (Table 9-3). Therefore, no impacts to vegetation as a result of TEC NO_x emissions are expected. SO₂ concentration increases of 1.09, 0.32, and 0.0123 µg/m³ for 3-hour, 24-hour, and annual periods, respectively, (Table 9-1) are much lower than plant injury thresholds (131 µg/m³ for 8 hours, 13 µg/m³ chronic) of the most sensitive vegetation (Table 9-4). Therefore, no impacts to vegetation are expected as a result of the TEC.

Air pollutant concentrations in the project vicinity are projected to be well below NAAQS standards and minimum threshold concentrations (Table 9-5), below which no wildlife acute toxicity is expected to occur. Most air pollution effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed in the previous paragraph, minimal impacts to vegetation are expected to occur as a result of the low emissions increases in Bradwell Bay due to TEC. Therefore, no adverse impacts to wildlife are expected.

Soil Characteristics

The large majority of the soils of Bradwell Bay are classified as Croatan-Dorovan Muck, with small islands of well drained Scranton and Leon sand around the perimeters. The Croatan-Dorovan soils are acidic histosols with deep organic surface horizons. The Leon sand is a spodosol, and the Scranton sand belongs to the psamment subgroup of entisols.

Soils Impact Evaluation

Dominant soil types (spodosol, psamment entisols) are well buffered to changes in pH as a result of high sulfate adsorption capacities. There is no sampling of atmospheric deposition in or near Bradwell Bay. Predicted maximum increase in atmospheric deposition of nitrogen and sulfur of 0.0072 and 0.0141 kg/ha/yr, respectively, as a result of this project, will have negligible impacts on the soils of Bradwell Bay (Table 9-2). Soil reaction (pH) values are listed in Table 9-15.

Table 9-15. Soil pHs for the Soils Found in Bradwell Bay NWA

Soil	Depth (inches)	Soil Reaction
Croatan-Dorovan Muck		
Croatan	0 to 27	<4.5
	>27	3.6 to 6.5
Dorovan	0 to 74	3.6 to 4.4
	74 to 80	4.5 to 5.5
Scranton sand	0 to 7	4.5 to 6.5
	>7	4.5 to 6.0
Leon sand	0 to 80	3.6 to 6.5

Source: USDA, NRCS soil surveys of Wakulla County, 1991.

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10.0 CLASS I IMPACT RESULTS

10.1 OVERVIEW

Comprehensive refined modeling was conducted to assess TEC Project Class I area air quality impacts in accordance with EPA, Federal Land Managers (FLM), and FDEP modeling guidance. This section provides the results of the TEC Project air quality assessment with respect to long-range transport impacts at five PSD Class I areas: the St. Marks, Bradwell Bay, and the Chassahowitzka NWAs in Florida and the Okefenokee and Wolf Island NWAs in Georgia. TEC Project air quality impacts in the vicinity of the project site were previously addressed in Section 7.0.

PSD Class I areas located within 300 km of TEC include the Okefenokee and Wolf Island National Wilderness Areas (NWAs) in Georgia, and the Bradwell Bay, St. Marks, and Chassahowitzka NWAs in Florida. The nearest PSD Class I area is the St. Marks NWA situated approximately 50 km (30 miles) west of the Project Site; distances from the Project Site to receptors at this Class I area range from 48.6 to 96.5 km. The TEC Project is located approximately 100 km (62 miles) east of the Bradwell Bay NWA; distances from the Project Site to receptors at this Class I area range from 99.7 to 111.2 km. The TEC Project is located approximately 115 km (72 miles) southwest of the Okefenokee NWA; distances from the Project Site to receptors at this Class I area range from 116.1 to 161.8.5 km. The TEC Project is located approximately 250 km (155 miles) southwest of the Wolf Island NWA; distances from the Project Site to receptors at this Class I area range from 248.2 to 253.1 km. The TEC Project is situated approximately 500 km (310 miles) northwest of the Everglades National Park; distances from the Project Site to receptors at this Class I area range from 506.6 to 634.7 km. The Class I impact analyses for the TEC Project addressed each of the five PSD Class I areas located within 300 km of the project site. Figure 10-1 provides the locations of these Class I areas in relation to the TEC Project.

10.2 CONCLUSIONS

Comprehensive dispersion modeling using the CALMET/CALPUFF/CALPOST modeling suite demonstrates that the TEC Project will have insignificant air quality impacts for

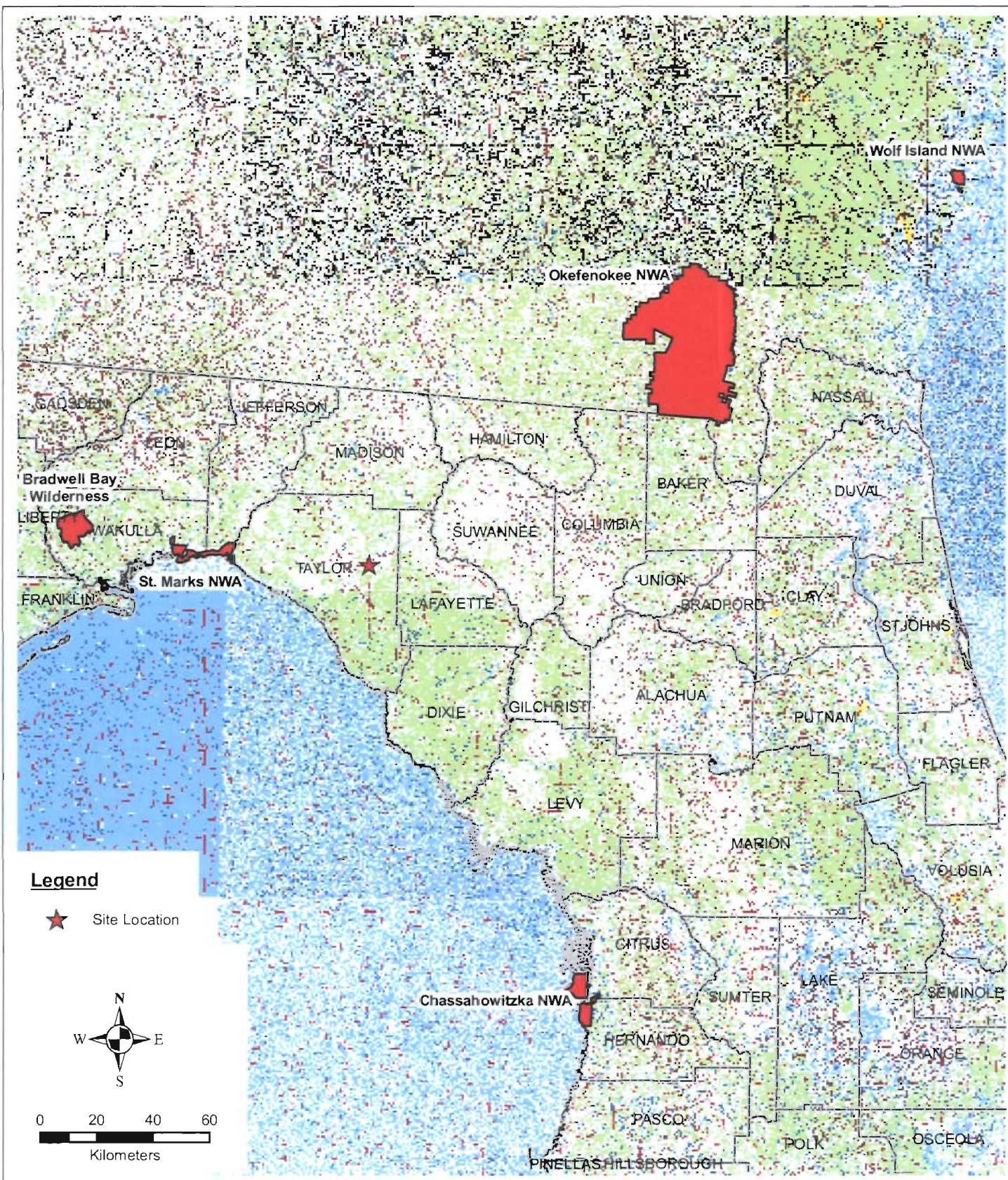


FIGURE 10-1.
LOCATION OF CLASS I AREAS

Sources: FGDL, 2003; ECT, 2006.

NO₂ and PM₁₀ (for all averaging periods), and for SO₂ (annual averages) at all five Class I areas evaluated. TEC air quality impacts are projected to exceed the PSD Class I SO₂ SILs for the 24- and 3-hour averaging periods at the St. Marks, Bradwell Bay, and Okefenokee NWAs. Accordingly, a cumulative assessment of SO₂ air quality impacts with respect to the PSD Class I increments was required for the St. Marks, Bradwell Bay, and Okefenokee NWAs. Multisource interactive modeling of regional PSD SO₂ increment consuming and expanding sources shows that cumulative SO₂ impacts at the St. Marks, Bradwell Bay, and Okefenokee NWA will be below the PSD Class I SO₂ increments.

Assessment of TEC Project regional haze impacts were conducted using the following methodologies:

- Procedure 1—EPA approved version of the CALPUFF modeling suite, background extinction computation Method 2, Class I-specific Raleigh scattering, and the current Interagency Monitoring of Protected Visual Environments (IMPROVE) light extinction algorithm.
- Procedure 2—Procedure 1 procedures with the new IMPROVE with the light extinction algorithm.
- Procedure 3—Procedure 2 procedures with background extinction computation Method 6. This is the approach that was required for Class I regional haze impacts under the Clean Air Visibility Rule (CAVR) for best available retrofit technology (BART) eligible emission sources.

Based on the results of these analyses, it is concluded that the TEC Project will not adversely affect visibility at any Class I area. Section 10.12.2 provides further discussion of regional haze impacts.

The TEC Project Class I area assessments of nitrogen and sulfur deposition demonstrate that that these impacts will not adversely affect the ecology of any Class I area.

10.3 GENERAL APPROACH

The required Class I area impact assessments were conducted using the CALPUFF dispersion model in accordance with the recommendations contained in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report, and EPA's Guideline on Air Quality Models (GAQM). As noted previously, the TEC Project assessment of regional haze impacts employed several additional modeling approaches.

The CALPUFF model was employed in a refined mode using 3 years (2001 through 2003) of 4-km resolution CALMET data and Class I area receptor grids as recommended by the National Park Service (NPS). The CALPUFF suite of programs, including the POSTUTIL and CALPOST postprocessing programs, was employed to develop estimates of TEC Project impacts on each of the five Class I areas located within 300 km for PSD increments, regional haze (with the exception of the Bradwell Bay NWA), and deposition. The Bradwell Bay NWA is not among the mandatory Federal Class I areas identified in 40 CFR 81, Subpart D, §81.407 as being subject to visibility protection.

10.4 MODEL SELECTION AND USE

Steady-state dispersion models do not consider temporal or spatial variations in plume transport direction nor do they limit the downwind transport of a pollutant as a function of wind speed and travel time. Due to these limitations, conventional steady-state dispersion models, such as AERMOD, are not considered suitable for predicting air quality impacts at receptors located more than 50 km from an emission source.

Because of the need to assess air quality impacts at PSD Class I areas, which are typically located at distances greater than 50 km from the emission sources of interest, EPA and FLM initiated efforts to develop dispersion models appropriate for the assessment of long-range transport of air pollutants. The IWAQM was formed to coordinate the model development efforts of EPA and the FLMs.

The IWAQM work plan indicates that a phased approach would be taken with respect to the implementation of recommendations for long-range transport modeling. In Phase 1, the IWAQM would review current EPA modeling guidance and issue an interim modeling approach applicable to projects undergoing permit review. For Phase 2, a review would be made of other available long-range transport models and recommendations developed for the most appropriate modeling techniques.

The Phase 1 recommendation, issued in April 1993, is to use the Lagrangian puff model, MESOPUFF II, for long-range transport air quality assessments. The Phase 2 recommendations, issued in December 1998, are contained in the IWAQM Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. Additional FLM guidance with respect to the assessment of visibility and deposition impacts is provided in the FLAG Phase I Report dated December 2000. The Phase 2 IWAQM recommendation is to apply the CALPUFF Modeling System to assess air quality impacts at distances greater than 50 km from an emission source. In April 2003, EPA designated the CALPUFF model as a preferred model (i.e., a model listed in Appendix A through W of 40 CFR 51, Summaries of Preferred Air Quality Models) for use in assessing the long-range transport of air pollutants.

The EPA GAQM indicates that the CALPUFF modeling system is appropriate for long-range transport (source-receptor distances of 50 to several hundred kilometers) of emissions from point, volume, area, and line sources. With the exception of the St. Marks NWA, all the receptors at the Class I areas evaluated are situated greater than 50 km from the Project Site. There are 101 receptors defined by NPS for the St. Marks NWA. Of these 101 receptors, 11 are located less than 50 km from TEC; the nearest St. Marks NWA receptor is located 48.6 km from the Project Site. Use of the CALPUFF modeling system was used for all St. Marks NWA receptors for the following reasons:

- The St. Marks NWA is located on the coast of the Gulf of Mexico. The CALPUFF modeling system, which includes algorithms that address coastal interaction effects, is considered technically superior to the AMS/EPA Regulatory Model (AERMOD). The CALMET meteorological model contains both overwater and overland boundary layer algorithms to simulate the

effects of water bodies on plume transport, dispersion, and deposition. The puff formulation of CALPUFF is designed to handle spatial changes in meteorological and dispersion conditions, including the abrupt changes that occur at the coastline of a major body of water. AERMOD does not consider coastal interaction effects.

- For regional haze light extinction calculations, use of a plume-simulating model such as CALPUFF is appropriate when the plume is sufficiently diffuse that it is not visually discernible as a plume, but instead could potentially alter visibility by effecting background haze. The IWAQM Phase 2 report states that such conditions occur starting 30 to 50 km from a source. The TEC main boiler will have a stack height of 550 ft and will be located 48.6 km from the nearest St. Marks NWA receptor. Stable atmospheric conditions that would cause little mixing of a plume (i.e., F class stability and a 1.0-meter-per-second wind speed) would be expected to occur for up to 3 hours in the morning when the nighttime inversion transitions to convective activity resulting in a plume downwind travel distance of approximately 10 km. After this distance, convective activity would occur with rapid mixing of the plume. For a discrete TEC plume to be potentially visible at the nearest St. Marks NWA receptor, these stable atmospheric conditions would need to persist for approximately 15 consecutive hours with a steady wind direction towards the St. Marks NWA. Accordingly, the TEC main boiler plume would not be expected to be discernible at the St. Marks NWA.
- The recommended CALPUFF model 50-km source-receptor distance is not considered an absolute threshold (i.e., plume dispersion characteristics would not be expected to differ significantly at exactly 50 km from an emission source). CALPUFF modeling system results will be essentially the same at receptors located 50.1 and 49.9 km from an emission source.
- The GAQM states that “CALPUFF is intended for use on scales from tens of meters from a source to hundreds of kilometers.” This is supported by the IWAQM Phase 2 report, which indicates that the diffusion algorithms in CALPUFF were designed to be suitable for both short and long distances.

- The tracer studies with which CALPUFF transport and diffusion capabilities were evaluated in the IWAQM Phase 2 report were generally over distances greater than 50 km. Recent additional studies of model performance have been performed at shorter distances, including at a power plant in New York state in complex terrain (at source-receptor distances of 2 to 8.5 km) and a second power plant in Illinois in simple terrain (at source-receptor distances in arcs ranging from 0.5 to 50 km from the stack). These studies demonstrate good model performance over source-receptor distances from a few hundred meters to 50 km.

The EPA-approved version of the CALPUFF modeling suite was used for the TEC Project Class I area impact assessments. The EPA-approved CALPUFF modeling suite is comprised of the following programs:

• CALPUFF	Version: 5.711a	Level: 040716.
• POSTUTIL	Version: 1.3	Level: 030402.
• CALPOST	Version: 5.51	Level: 030709.

These programs were used to assess PSD Class I increments, regional haze, and nitrogen and sulfur deposition impacts.

The CALPUFF modeling system consists of three main components: CALMET, CALPUFF, and CALPOST. Each of these components is described in the following subsections.

10.4.1 CALMET

CALMET is a meteorological model that develops hourly wind and temperature fields on a three-dimensional gridded modeling domain. The meteorological file produced by CALMET for use by CALPUFF also includes two-dimensional parameters such as mixing height, surface characteristics, and dispersion properties.

CALMET requires a number of input data files to develop the gridded three- and two-dimensional meteorological file used by CALPUFF. The specific meteorological data used by the CALMET program include:

- Penn State/National Center for Atmospheric Research (NCAR) mesoscale model gridded, prognostic wind field data (terrain elevation, land use code, sea level pressure, rainfall amount, snow cover indicator, pressure, temperature/dew point, wind direction, and wind speed).
- Surface station weather data (wind speed, wind direction, ceiling height, opaque sky cover, air temperature, relative humidity, station pressure, and precipitation type code).
- Upper air sounding (mixing height) data (pressure, height above sea level, temperature, wind direction, and wind speed at each sounding).
- Surface station precipitation data (precipitation rates).
- Overwater data (air-sea surface temperature difference, air temperature, relative humidity, overwater mixing height, wind speed, and wind direction).
- Geophysical data (land use type, terrain elevation, surface parameters including surface roughness, length, albedo, Bowen ratio, soil heat flux, and vegetation leaf area index, and anthropogenic heat flux).

Further technical discussion of the CALMET model can be found in Section 2 of the User's Guide for the CALMET meteorological model dated January 2000.

VISTAS has developed a 3-year (2001 through 2003) CALMET dataset for a fine, 4-km, subregional domain that covers all of Florida and the adjacent Class I areas of interest to Florida. The VISTAS fine-grid CALMET dataset (containing more than 250 gigabytes [GB] of data) was obtained from FDEP and was used in the TEC Project Class I impact assessments.

10.4.2 CALPUFF

CALPUFF is a transport and puff model that advects *puffs* of material from an emission source. These puffs undergo various dispersion and transformation simulation processes

as they are advected from an emission source to a receptor of interest. The simulation processes include wet and dry deposition and chemical transformation. CALPUFF typically uses the gridded meteorological data created by the CALMET program. CALPUFF, when used in a screening mode, can also use nongridded meteorological data similar to that used by a steady-state dispersion model such as AERMOD. The distribution of puffs by CALPUFF explicitly incorporates the temporal and spatial variations in the meteorological fields thereby overcoming one of the main shortcomings of steady-state dispersion models. Further technical discussion of the CALPUFF model can be found in Section 2 of the User's Guide for the CALPUFF Model dated January 2000.

There are a number of optional CALPUFF input files that were not used for the TEC Project Class I area impact assessments. These include time-varying emission rates, user-specified deposition velocities and chemical transformation conversion rates, complex terrain receptor and hill geometry data, and coastal boundary data.

CALPUFF generates output files consisting of hourly concentrations, deposition fluxes, and data required for visibility assessments for each receptor. These CALPUFF output files are subsequently processed by the POSTUTIL and CALPOST programs to provide impact summaries for the pollutants and averaging periods of interest.

The various CALPUFF program options are implemented by means of a control file. CALPUFF options selected for the TEC Project Class I area impact assessments conform to the recommendations contained in the IWQAM Phase 2 report and EPA's GAQM. Key CALPUFF model options selected for the TEC Class I impact assessments are listed:

- CALPUFF domain configured to include the TEC main boiler and all Class I receptors with a minimum 50-km buffer in all directions.
- 4-km spacing meteorological and computational grid.
- Class I receptors as defined by the NPS.
- Modeling of 11 species (SO_2 , SO_4 , NO_x , nitric acid [HNO_3], nitrate, $\text{PM}_{8.0}$, $\text{PM}_{4.25}$, $\text{PM}_{1.875}$, $\text{PM}_{1.125}$, $\text{PM}_{0.8125}$, and $\text{PM}_{0.6250}$).
- Use of the MESOPUFF II chemical mechanism module.

- IWAQM default guidance, including Pasquill-Gifford dispersion coefficients.
- 2001 through 2003 ozone data from CASTNet and AIRS stations.
- Background ammonia (NH₃) concentration of 0.5 ppb.
- Integrated puff sampling methodology.
- No consideration of building downwash.

The PM fractions indicated herein address the PM size distribution expected for the TEC main boiler at the outlet of the emission control systems. The Class I impacts for the PM₁₀ fractions, together with primary sulfate impacts, were summed to obtain total PM₁₀ impacts. Appendix C contains an example CALPUFF output file. This output file shows all of the CALPUFF options employed for the TEC Project Class I area impact analyses.

10.4.3 POSTUTIL

POSTUTIL is a postprocessing program used to process the concentration generated by CALPUFF. POSTUTIL was used to recompute the HNO₃/nitrate concentration partition, consolidate the wet and dry nitrogen and sulfur fluxes, and convert sulfate and nitrate fluxes to total sulfur and total nitrogen fluxes. Class I impacts for the TEC main boiler PM₁₀ fractions, together with primary sulfate impacts, were summed using the POSTUTIL program to develop total PM₁₀ impacts. Appendix C contains an example POSTUTIL output file. This output file shows all of the POSTUTIL options employed for the TEC Project Class I area impact analysis.

10.4.4 CALPOST

CALPOST is a postprocessing program used to process the concentration, deposition, and visibility files generated by CALPUFF. The CALPOST program was formulated to average and report pollutant concentrations or wet/dry deposition fluxes using the hourly data contained in the CALPUFF output files. CALPOST can produce summary tables of pollutant concentrations and depositions for each receptor for various averaging times and can develop ranked lists of these impacts. For visibility-related modeling (e.g., regional haze), CALPOST uses the CALPUFF generated pollutant concentrations to calculate extinction coefficients and other related indicators of visibility.

For visibility assessments, background conditions were estimated using *natural* background data (i.e., absent anthropogenic influences). The CALPOST program was then used to compute background extinction coefficients using the natural background data and the IWQAM recommended extinction efficiency for each species.

Similar to the CALPUFF program, the various CALPOST program options are implemented by means of a control file. CALPOST options selected for the TEC Project Class I impact assessments conform to the recommendations contained in the FLAG Phase I Report. Appendix C contains an example CALPOST output file. This output file shows all of the CALPOST options employed for the TEC Project Class I area impact analysis.

10.5 RECEPTOR GRIDS

As noted previously, the Okefenokee and Wolf Island NWAs in Georgia and the Bradwell Bay, St. Marks, and Chassahowitzka NWAs in Florida are all located within 300 km from the TEC Project. The receptor grids developed for the TEC Project addressed each of these Class I areas.

Accordingly, the TEC Project Class I area receptor grids included the Okefenokee NWA (500 discrete receptors), Wolf Island NWA (30 discrete receptors), Bradwell Bay NWA (132 discrete receptors), Chassahowitzka NWA (113 discrete receptors), and St. Marks NWA (101 discrete receptors) receptors identified by the NPS for these five Class I areas. The NPS receptors, determined in geographic (latitude and longitude) and Universal Transverse Mercator (UTM) coordinates using the NPS Convert Class I Areas program, were converted to Lambert Conformal Conic (LCC) coordinates consistent with the VIS-TAS fine 4-km CALMET grid parameters (i.e., two matching parallels, latitude/longitude of the projection origin, and coordinate datum) using the CALPUFF COORDS utility program.

All receptors were included in each CALPUFF model run. In CALPOST, only the receptor ranges for the specific Class I areas were processed. The range of receptors used for each Class I area are shown in Table 10-1.

10.6 MODELED EMISSION SOURCES

TEC Project modeled emission sources included only the main boiler—the primary Project emission source. The TEC Project point and fugitive material handling and cooling tower emission sources will have minor PM₁₀ emission rates and low release heights. Accordingly, these emission sources will have a negligible impact at the distant Class I areas. The TEC Project auxiliary boiler and emergency diesel engines will have relatively minor emission rates, will operate intermittently, and will generally not operate concurrently with the main boiler. Accordingly, these TEC Project emission sources will also have negligible impacts at the Class I areas.

Main boiler Case 3 fuel type (PRB/petcoke blend) emissions and stack data were used in the PSD Class I analysis since this operating case results in the highest emission rates. Table 10-2 summarizes main boiler stack parameters, emission rates, PM₁₀ speciation, and visibility components used in the CALPUFF modeling assessments.

10.7 MODEL RESULTS

TEC Project CALPUFF/CALPOST modeling results for Class I PSD increments, deposition impacts, and regional haze (i.e., visibility) at the five Class I areas evaluated are discussed in the following subsections.

10.7.1 PSD CLASS I SIGNIFICANT IMPACT LEVEL ANALYSIS

Table 10-3 summarizes TEC NO₂, SO₂, and PM₁₀ impacts with respect to the PSD SILs. This table provides the highest annual average impacts (for NO₂, SO₂, and PM₁₀), highest 3-hour average impacts (for SO₂), and highest 24-hour average impacts (for SO₂ and PM₁₀) for each of the five Class I areas evaluated. With the exception of the 24- and 3-hour average SO₂ impacts at the St. Marks, Bradwell Bay, and Okeefenokee NWAs, all impacts are below the PSD Class I SILs for all pollutants and all averaging periods.

Table 10-1. Class I Area Receptor Numbers

Class I NWAs	Receptor Number			CALPOST Setting for NCRECP
	Start	End	Total	
Chassahowitzka	1	113	113	113*1
St. Marks	114	214	101	113*0, 101*1
Okefenokee	215	714	500	214*0, 500*1
Bradwell Bay	715	846	132	714*0, 132*1
Wolf Island	847	876	30	846*0, 30*1

Source: ECT, 2007.

Table 10-2. TEC Main Boiler—CALPUFF Modeling Data

A. Stack Parameters

Parameter	Units	Main Boiler	Units	Main Boiler
Height Above Grade	ft	550	m	167.6
Base Elevation	ft	65.0	m	19.8
Exit Diameter	ft	30.80	m	9.39
Stack Exit Area	ft ²	745.1	m ²	69.2
Exit Temperature	°F	130.0	K	327.6
Exit Velocity	ft/sec	52.7	m/sec	16.1
Exhaust Flow Rate	actual ft ³ /min	2,355,880	actual m ³ /min	66,711

B. Emission Rates (@ 100% load)

Design Premises:

Power Output	818,532	kW _{we} (nominal, gross)
Heat Rate (gross)	9,132	Btu/kWh (HHV)
Heat Input (gross)	7,475	mmBtu/hr (HHV)

Unit	Sulfur Dioxide (SO ₂), 24-hr		Sulfur Dioxide (SO ₂), 3-hr	
	(lb/mmBtu)	(lb/hr)	(lb/mmBtu)	(lb/hr)
Main Boiler	0.055	411.1	0.070	523.3

Unit	Sulfur Dioxide (SO ₂), Annual		Nitrogen Oxides (NO _x), 24-hr, Annual	
	(lb/mmBtu)	(lb/hr)	(lb/mmBtu)	(lb/hr)
Main Boiler	0.040	299.0	0.050	373.8

Unit	Total Condensable PM ₁₀ , 24-hr		Filterable PM ₁₀ , 24-hr	
	(lb/mmBtu)	(lb/hr)	(lb/mmBtu)	(lb/hr)
Main Boiler	0.0113	84.6	0.013	97.2

Unit	Non-Sulfate Inorganic Condensable PM ₁₀ , 24-hr		Organic Condensable PM ₁₀ , 24-hr	
	(lb/mmBtu)	(lb/hr)	(lb/mmBtu)	(lb/hr)
Main Boiler	0.0036	27.1	0.0023	16.9

Unit	Sulfuric Acid Mist (H ₂ SO ₄), 24-hr		Ammonium Sulfate [(NH ₄) ₂ SO ₄], 24-hr	
	(lb/mmBtu)	(lb/hr)	(lb/mmBtu)	(lb/hr)
Main Boiler	0.0040	29.9	0.0014	10.7

Unit	Total Primary Sulfate (SO ₄), 24-hr		Total PM ₁₀ , 24-hr	
	(lb/mmBtu)	(lb/hr)	(lb/mmBtu)	(lb/hr)
Main Boiler	0.0050	37.1	0.0243	181.8

Note: All PM₁₀ emission rates reflect 24-hour and annual average rates.**C. Stack Coordinates**

Unit	UTM Coordinates—NAD 1927		
	Zone	X—Easting (km)	Y—Northing (km)
Main Boiler	17	261.449	3,330.238

Unit	Lambert Conformal (Florida CALMET Subdomain)		
		X—Easting (km)	Y—Northing (km)
Main Boiler		1,304.6959	-1,003.3854

Sources: S&L, 2007.
ECT, 2007.

Table 10-2. TEC Main Boiler—CALPUFF Modeling Data (Continued, Page 2 of 2)

D. PM₁₀ Size Distribution (from Table 1.1-6, Baghouse, AP-42, 9/98)

Particle Size (microns)	Filterable PM ₁₀		Organic Condensable PM ₁₀		Non-Sulfate Inorganic Condensable PM ₁₀ , 24-hr	
	(%)	(lb/hr)	(%)	(lb/hr)	(%)	(lb/hr)
8.0000	16.3	15.8				
4.2500	26.1	25.4				
1.8750	23.9	23.2				
1.1250	6.5	6.3				
0.8125	12.0	11.6	50.0	8.5	50.0	13.6
0.6250	15.2	14.8	50.0	8.5	50.0	13.6
Totals	100.00	97.2	100.0	16.9	100.0	27.1

Non-Sulfate PM ₁₀ Fraction	Emission Rate (lb/hr)	Percent of Filterable PM ₁₀ (%)	Percent of Condensable PM ₁₀ (%)
Coarse (> 2.5 um) Filterable	41.2	42.4	N/A
Fine (< 2.5 um) Filterable	56.0	57.6	N/A
Coarse (> 2.5 um) Condensable	0.0	N/A	0.0
Fine (< 2.5 um) Condensable	44.0	N/A	100.0
Totals	141.2	100.0	100.0

E. PM₁₀ Size Distribution - Visibility Components

Particle Size (microns)	Filterable PM ₁₀				Non-Sulfate Condensable PM ₁₀	
	PMC (lb/hr)	SOIL (lb/hr)	EC (lb/hr)	Totals (lb/hr)	OC (SOA) (lb/hr)	SOIL (lb/hr)
8.0000	15.8			15.8		
4.2500	25.4			25.4		
1.8750		23.2		23.2		
1.1250		6.3		6.3		
0.8125		11.6		11.6	8.5	13.6
0.6250		12.7	2.1	14.8	8.5	13.6
Totals	41.2	53.9	2.1	97.2	16.9	27.1

Coarse Inorganic PM (PMC)	100.0	% of coarse filterable PM ₁₀
Fine Filterable Inorganic PM (SOIL)	96.3	% of fine filterable PM ₁₀
Fine Elemental Carbon PM (EC)	3.7	% of fine filterable PM ₁₀
Fine Organic Carbon PM (OC)	20.0	% of total condensable PM ₁₀
Fine Non-Sulfate Inorganic PM (SOIL)	32.0	% of total condensable PM ₁₀

F. Visibility Component Summary (excluding SO₂)

Particle Size (microns)	Emission Rates				
	PMC (lb/hr)	SOIL (lb/hr)	EC (lb/hr)	OC (lb/hr)	Totals (lb/hr)
8.0000	15.8				15.8
4.2500	25.4				25.4
1.8750		23.2			23.2
1.1250		6.3			6.3
0.8125		11.6		8.5	33.6
0.6250		12.7	2.1	8.5	36.8
Totals	41.2	53.9	2.1	16.9	114.1
Fraction of Total	0.292	0.574	0.015	0.120	1.000

G. Visibility Component Summary (excluding SO₂)

Particle Size (microns)	Fraction of Totals				
	PMC (fraction)	SOIL (fraction)	EC (fraction)	OC (fraction)	Totals (fraction)
8.0000	1.000				1.000
4.2500	1.000				1.000
1.8750		1.000			1.000
1.1250		1.000			1.000
0.8125		0.748		0.252	1.000
0.6250		0.714	0.056	0.230	1.000

Sources: S&L, 2007.
ECT, 2007.

Table 10-3. TEC Main Boiler—Summary of PSD Class I Air Quality Impacts: NO_x, SO₂, and PM₁₀

Pollutant	Year of Meteorology	Averaging Period	Class I Area Impact				
			St. Marks NWA (µg/m ³)	Chassahowitzka NWA (µg/m ³)	Okefenokee NWA (µg/m ³)	Bradwell Bay NWA (µg/m ³)	Wolf Island NWA (µg/m ³)
NO _x	2001	Annual	0.0124	0.0017	0.0052	0.0065	0.0015
	2002		0.0209	0.0025	0.0069	0.0093	0.0016
	2003		0.0139	0.0023	0.0078	0.0058	0.0023
	Maximum		0.0209	0.0025	0.0078	0.0093	0.0023
	PSD SIL		0.1	0.1	0.1	0.1	0.1
	% of PSD SIL		20.9	2.5	7.8	9.3	2.3
Exceed PSD SIL			No	No	No	No	No
SO ₂	2001	Annual	0.0175	0.0041	0.0077	0.0093	0.0025
	2002		0.0263	0.0040	0.0100	0.0123	0.0028
	2003		0.0178	0.0037	0.0099	0.0081	0.0036
	Maximum		0.0263	0.0041	0.0100	0.0123	0.0036
	PSD SIL		0.1	0.1	0.1	0.1	0.1
	% of PSD SIL		26.3	4.1	10.0	12.3	3.6
Exceed PSD SIL			No	No	No	No	No
SO ₂	2001	24-Hour	0.67	0.16	0.19	0.32	0.05
	2002		0.45	0.10	0.22	0.29	0.08
	2003		0.49	0.13	0.32	0.25	0.10
	Maximum		0.67	0.16	0.32	0.32	0.10
	PSD SIL		0.2	0.2	0.2	0.2	0.2
	% of PSD SIL		333.2	80.1	161.1	160.3	50.5
Exceed PSD SIL			Yes	No	Yes	Yes	No
SO ₂	2001	3-Hour	1.98	0.51	0.83	0.99	0.23
	2002		1.94	0.40	0.70	1.09	0.25
	2003		2.41	0.69	0.93	1.01	0.33
	Maximum		2.41	0.69	0.93	1.09	0.33
	PSD SIL		1.0	1.0	1.0	1.0	1.0
	% of PSD SIL		240.7	68.6	93.1	109.3	33.1
Exceed PSD SIL			Yes	No	No	Yes	No
PM ₁₀	2001	Annual	0.0151	0.0053	0.0073	0.0090	0.0031
	2002		0.0216	0.0046	0.0095	0.0119	0.0033
	2003		0.0147	0.0041	0.0088	0.0082	0.0040
	Maximum		0.0216	0.0053	0.0095	0.0119	0.0040
	PSD SIL		0.2	0.2	0.2	0.2	0.2
	% of PSD SIL		10.8	2.6	4.7	5.9	2.0
Exceed PSD SIL			No	No	No	No	No
PM ₁₀	2001	24-Hour	0.27	0.17	0.13	0.15	0.04
	2002		0.24	0.07	0.19	0.20	0.06
	2003		0.23	0.09	0.16	0.16	0.07
	Maximum		0.27	0.17	0.19	0.20	0.07
	PSD SIL		0.3	0.3	0.3	0.3	0.3
	% of PSD SIL		90.0	55.8	64.7	67.1	24.6
Exceed PSD SIL			No	No	No	No	No

Source: ECT, 2007.

Accordingly, cumulative modeling was conducted for the St. Marks, Bradwell Bay, and Okefenokee NWAs to determine PSD Class I SO₂ increment consumption for each area.

10.7.2 CUMULATIVE PSD CLASS I SO₂ INCREMENT ANALYSIS

The modeled emissions inventory of PSD SO₂ increment consuming and expanding sources for the North Florida region was obtained from FDEP. This inventory was supplemented with PSD consuming and expanding sources located in Alabama and Georgia that were used in the assessing Class I impacts for the proposed Longleaf Energy facility. Figure 10-2 depicts the locations of the modeled PSD SO₂ emission sources. Table 10-4 shows, for each modeled SO₂ increment consuming emission source, the code used to identify the emission source, facility name, stack coordinates (in both UTM and LCC coordinates), stack parameters (elevation above grade, exit diameter, exit exhaust velocity, and exit exhaust temperature), and the SO₂ emission rate. Table 10-5 provides corresponding data for the modeled SO₂ increment expanding sources. The results of the cumulative SO₂ modeling are provided in Table 10-6. As shown in this table, cumulative SO₂ increment consumption for the St. Marks, Bradwell Bay, and Okefenokee NWAs are all below the Class I increments.

10.7.3 SULFUR AND NITROGEN DEPOSITION

Table 10-7 summarizes TEC total wet and dry annual sulfur and nitrogen deposition rates for each Class I area evaluated. As shown, the FLM sulfur and nitrogen deposition analysis threshold (DAT) of 0.01 kg/ha/yr is projected to be exceeded for the St. Marks (nitrogen and sulfur), Okefenokee (sulfur), and Bradwell Bay NWAs (sulfur). Deposition rates above the generic FLM DAT levels require a consideration of Class I-specific impacts.

Although deposition impacts are projected to exceed the FLM DAT for sulfur and nitrogen, analyses of the Class I areas affected indicates that the modeled deposition rates are well below levels that would have an adverse impact on soils or vegetation. A thorough discussion of the TEC sulfur and nitrogen deposition impacts for the five Class I areas evaluated is provided in Section 9.0

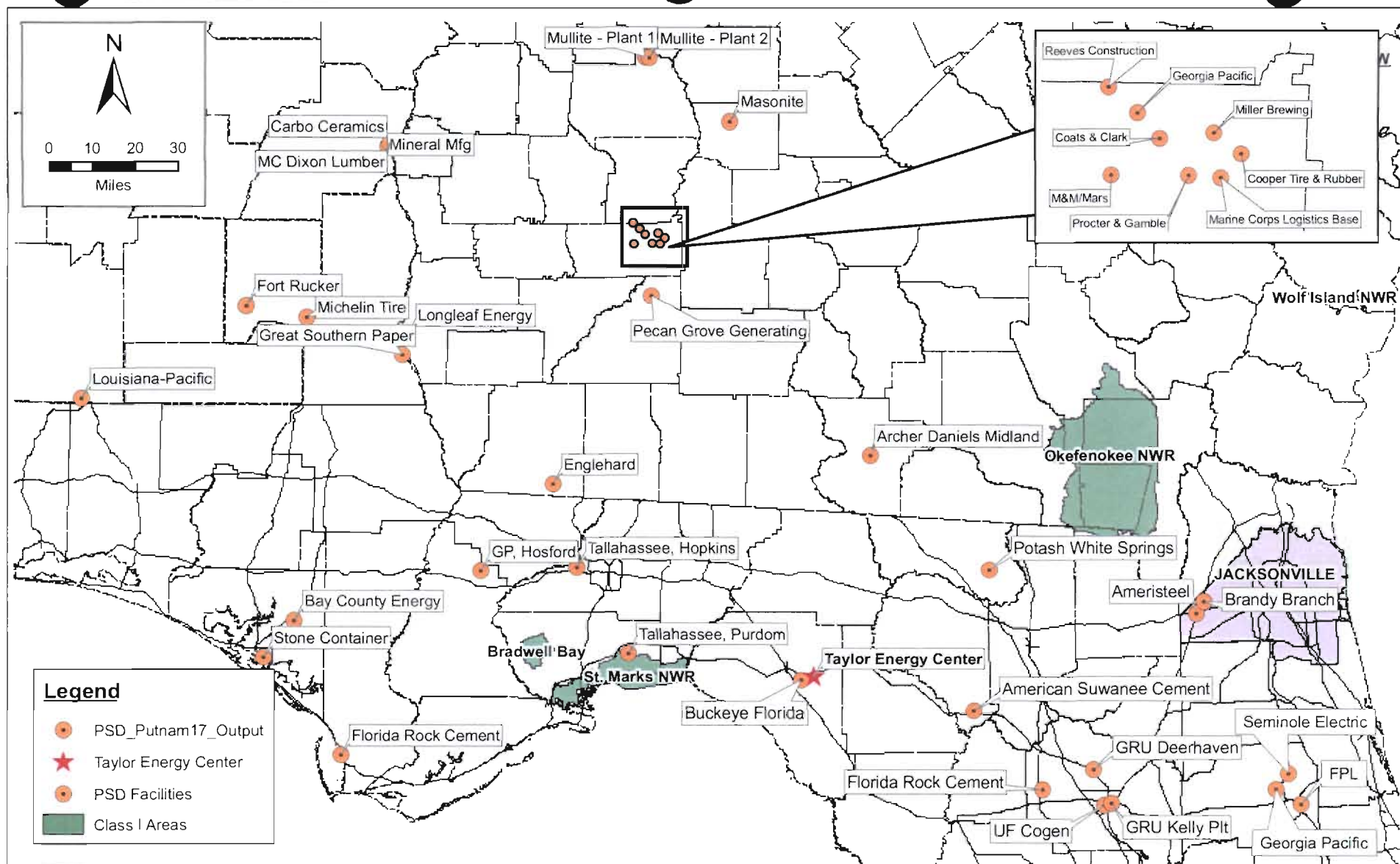


FIGURE 10-2.
PSD SO₂ SOURCE LOCATIONS

Sources: FGDL, 2004; GA GIS Clearinghouse, 2004; ECT, 2007.

Table 10-4. PSD SO₂ Increment Consuming Emission Sources

(Continued, Page 1 of 3)

Model Identification		State	Facility Name	Stack Coordinates				Stack Parameters					SO ₂
Number	Name			UTM		LLC		Elevation	Height	Diameter	Velocity	Temperature	Emission Rate
				Easting (km)	Northing (km)	Easting (km)	Northing (km)	(m)	(m)	(m)	(m/s)	(K)	(g/s)
701	MAIN BOILER	FL	Taylor Energy Center	261.449	3330.238	1304.696	-1003.385	19.8	167.60	9.39	16.10	327.60	51.80
1	RB1	FL	Stone Container	54.680	3343.327	1100.328	-1022.846	0.0	71.00	1.96	26.50	421.00	16.35
2	RB2	FL	Stone Container	54.680	3343.327	1100.328	-1022.846	0.0	71.00	1.96	27.48	428.00	16.35
3	SDT1	FL	Stone Container	54.680	3343.327	1100.328	-1022.846	0.0	71.00	1.83	5.25	347.40	0.13
4	SDT2	FL	Stone Container	54.680	3343.327	1100.328	-1022.846	0.0	71.00	1.83	4.56	347.40	0.13
5	LK1	FL	Stone Container	54.680	3343.327	1100.328	-1022.846	0.0	18.60	2.44	11.84	348.00	0.59
6	BB3	FL	Stone Container	54.680	3343.327	1100.328	-1022.846	0.0	64.90	2.39	26.18	338.00	61.10
7	BB4	FL	Stone Container	54.680	3343.327	1100.328	-1022.846	0.0	64.90	2.39	28.17	332.00	149.10
8	BCEB12	FL	Bay County Energy	66.623	3356.646	1109.945	-1007.675	3.0	38.10	1.37	17.50	477.60	9.02
9	FCPPB9	FL	Florida Rock Cement	82.806	3305.630	1134.456	-1055.536	0.0	51.80	4.27	10.33	343.10	76.23
10	TALPURD8	FL	City of Tallahassee, Purdom	191.815	3340.914	1236.605	-1002.283	0.0	60.90	5.00	15.38	353.00	7.82
11	TALHOPK2	FL	City of Tallahassee, Hopkins	173.216	3373.756	1212.634	-972.888	40.2	76.20	4.27	21.00	400.00	410.76
12	GPHOS1	FL	Georgia Pacific, Hosford	137.221	3373.464	1177.040	-979.234	58.0	39.60	2.59	15.31	399.30	0.85
13	GPHOS2	FL	Georgia Pacific, Hosford	137.221	3373.464	1177.040	-979.234	58.0	30.50	2.18	18.46	340.90	0.001
14	GPHOS10	FL	Georgia Pacific, Hosford	137.221	3373.464	1177.040	-979.234	58.0	42.00	1.68	6.35	644.30	0.01
15	LK4	FL	Buckeye Florida, Foley Mill	256.814	3328.926	1303.077	-1003.129	16.0	38.10	2.23	15.17	510.90	3.94
16	RB4	FL	Buckeye Florida, Foley Mill	256.471	3328.816	1302.755	-1003.296	16.0	68.58	2.90	27.88	499.80	22.26
17	SDT4	FL	Buckeye Florida, Foley Mill	256.485	3328.823	1302.768	-1003.288	16.0	37.80	1.22	12.94	341.50	0.13
18	COMBO	FL	Buckeye Florida, Foley Mill	256.564	3328.847	1302.842	-1003.250	16.0	68.58	3.96	18.95	366.50	62.87
19	BAYENERGY	FL	Bay Energy	66.618	3356.546	1109.956	-1007.775	15.0	38.10	1.37	17.50	477.60	9.00
20	AMSUWCEM	FL	American Suwanee Cement	321.400	3315.900	1369.361	-1004.979	18.0	96.00	2.87	14.10	369.30	3.58
21	AMSUWCEM	FL	American Suwanee Cement	321.300	3315.800	1369.279	-1005.096	18.0	96.00	2.87	14.10	374.80	4.31
22	FLRKILN1	FL	Florida Rock Cement	346.400	3285.700	1399.376	-1030.635	27.0	76.20	2.90	14.60	453.20	3.63
23	FLRKILN2	FL	Florida Rock Cement	346.400	3285.700	1399.376	-1030.635	27.0	95.90	2.90	16.00	453.20	4.41
24	UFCOGEN	FL	UF Cogeneration	369.390	3279.290	1423.307	-1033.019	30.0	28.35	2.98	24.62	398.20	26.00
25	GRULKCC1	FL	GRU Kelly Plt	372.000	3280.000	1425.775	-1031.862	38.0	31.09	4.72	18.96	389.90	6.50
26	EAFBH1	FL	Ameristeel	405.800	3350.300	1447.085	-956.260	26.2	35.05	5.79	13.44	383.20	4.03
27	REHEATN	FL	Ameristeel	405.800	3350.300	1447.085	-956.260	26.2	20.12	1.77	13.72	522.00	0.02
28	RH2	FL	Ameristeel	405.800	3350.300	1447.085	-956.260	26.2	20.12	1.77	13.72	522.00	0.02
29	S123NG	FL	Brandy Branch	408.800	3354.500	1449.326	-951.576	25.0	57.91	5.49	21.28	403.00	12.36
30	SFP	FL	Brandy Branch	408.900	3354.500	1449.425	-951.559	25.0	7.32	0.15	60.02	616.00	0.004
31	GRUDH2	FL	GRU Deerhaven	365.700	3292.600	1417.338	-1020.447	57.0	106.68	5.64	15.24	408.10	367.16
32	GRUDHCC	FL	GRU Deerhaven	365.500	3292.600	1417.139	-1020.482	57.0	15.85	4.30	51.21	866.50	6.68
33	SULACC&D	FL	Potash White Springs	328.300	3368.800	1367.090	-951.353	24.0	45.70	1.59	28.70	356.00	96.60
34	SULACE&F	FL	Potash White Springs	328.300	3368.800	1367.090	-951.353	24.0	61.00	2.90	9.30	356.00	105.00
35	AUXBLRE	FL	Potash White Springs	328.300	3368.800	1367.090	-951.353	24.0	15.30	1.60	15.90	428.00	21.50
36	AUXBLRB	FL	Potash White Springs	328.300	3368.800	1367.090	-951.353	24.0	10.70	1.46	9.50	468.00	22.00
37	AUXBLRC&D	FL	Potash White Springs	328.300	3368.800	1367.090	-951.353	24.0	31.70	1.98	15.20	468.00	41.88
38	DAP2ZTR	FL	Potash White Springs	328.300	3368.800	1367.090	-951.353	24.0	42.70	2.44	13.10	325.00	0.69
137	SEC112	FL	Seminole Electric, Palatka	438.800	3289.200	1487.370	-1013.610	24.4	205.74	10.97	9.14	326.50	680.39
138	SEC13	FL	Seminole Electric, Palatka	438.800	3289.200	1487.370	-1013.610	24.4	205.74	7.92	18.84	325.37	155.99
139	FPL1C	FL	Florida Power & Light, Putnam	443.300	3277.600	1493.860	-1024.370	24.4	22.25	14.63	29.29	437.59	415.80
140	GP1C	FL	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.4	62.79	1.52	10.33	354.98	0.97
141	GP2C	FL	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.4	72.18	2.44	26.18	484.98	184.20
142	GP3C	FL	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.4	72.18	2.44	28.13	513.98	121.10
143	GP4C	FL	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.4	70.07	3.66	20.09	490.98	13.83
144	GP5C	FL	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.4	39.90	1.22	21.52	346.48	4.35
145	GP6C	FL	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.4	76.17	1.22	5.49	343.98	3.94
39	LS001	AL	Carbo Ceramics	106.541	3534.270	1119.721	-825.469	76.2	4.27	0.51	8.08	455.38	0.04
40	LS002	AL	Carbo Ceramics	106.541	3534.270	1119.721	-825.469	76.2	34.14	0.49	87.86	505.38	0.06
41	LS003	AL	Carbo Ceramics	106.541	3534.270	1119.721	-825.469	76.2	34.14	0.91	31.26	369.83	0.03
42	LS004	AL	Carbo Ceramics	106.541	3534.270	1119.721	-825.469	76.2	34.14	0.49	14.25	422.05	0.82
43	LS005	AL	Carbo Ceramics	106.541	3534.270	1119.721	-825.469	76.2	27.13	1.22	17.92	393.16	0.12
44	LS006	AL	Carbo Ceramics	106.541	3534.270	1119.721	-825.469	76.2	17.98	0.46	17.37	391.49	0.03
45	LS007	AL	Carbo Ceramics	106.541	3534.270	1119.721	-825.469	76.2	17.98	0.46	17.37	391.49	0.04
46	LS008	AL	Mineral Manufacturing Corp	102.970	3527.747	1117.293	-832.503	91.4	30.48	2.44	9.10	378.72	11.47
47	LS009	AL	Sony Magnetic Products - Dothan	75.285	3463.852	1100.661	-900.213	96.0	12.19	0.71	3.15	455.38	0.16
48	LS010	AL	Sony Magnetic Products - Dothan	75.285	3463.852	1100.661	-900.213	97.8	12.19	0.59	4.47	455.38	0.09
49	LS011	AL	Sony Magnetic Products - Dothan	75.285	3463.852	1100.661	-900.213	97.5	6.10	0.70	9.96	383.16	0.03
50	LS012	AL	Sony Magnetic Products - Dothan	75.285	3463.852	1100.661	-900.213	96.0	12.19	0.71	3.15	455.38	0.16
51	LS013	AL	Sony Magnetic Products - Dothan	75.285	3463.852	1100.661	-900.213	96.0	12.19	0.61	2.14	455.38	0.08
52	LS014	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	6.10	0.30	7.96	444.27	0.27
53	LS015	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	6.10	0.30	7.96	444.27	0.27

Table 10-4. PSD SO₂ Increment Consuming Emission Sources

(Continued, Page 2 of 3)

Model Identification		State	Facility Name	Stack Coordinates				Stack Parameters					SO ₂ Emission Rate (g/s)
				UTM		LLC		Elevation (m)	Height (m)	Diameter (m)	Velocity (m/s)	Temperature (K)	
Number	Name			Easting (km)	Northing (km)	Easting (km)	Northing (km)						
54	LS016	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	6.10	0.24	6.92	494.27	0.13
55	LS017	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	6.10	0.25	6.43	494.27	0.13
56	LS018	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	8.23	0.91	1.06	508.72	0.55
57	LS019	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	8.23	0.91	1.59	508.72	0.82
58	LS020	AL	Fort Rucker - HQ US Army Aviation Center	50.509	3475.138	1074.311	-893.197	99.1	8.23	0.91	1.87	508.72	0.97
59	LS021	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	12.19	0.91	1.44	399.83	0.78
60	LS022	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	7.32	0.91	1.87	508.72	0.97
61	LS023	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	16.46	0.46	13.80	488.72	0.64
62	LS024	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	16.46	0.46	13.80	488.72	0.64
63	LS025	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	12.19	0.30	7.11	444.27	0.24
64	LS026	AL	Fort Rucker - HQ US Army Aviation Center	51.864	3476.068	1075.495	-892.053	99.1	9.14	0.61	7.21	466.49	1.65
65	LS027	AL	Fort Rucker - HQ US Army Aviation Center	51.953	3475.862	1075.617	-892.242	99.1	9.14	0.61	7.21	466.49	1.65
66	LS028	AL	Michelin Tire Corp	74.455	3470.721	1098.694	-893.567	110.3	15.24	0.61	14.39	433.16	1.60
67	LS029	AL	Michelin Tire Corp	74.455	3470.721	1098.694	-893.567	110.3	15.24	0.61	14.39	433.16	1.60
68	LS030	AL	Michelin Tire Corp	74.455	3470.721	1098.694	-893.567	109.7	28.96	1.07	9.30	433.16	11.87
69	LS031	AL	MC Dixon Lumber Co	107.213	3535.536	1120.171	-824.106	80.5	6.10	1.28	18.27	458.72	0.28
70	LS032	AL	Louisiana-Pacific Corp	-10.608	3442.608	1019.348	-935.446	89.0	24.61	1.40	2.58	510.94	0.01
71	LS033	AL	Louisiana-Pacific Corp	-10.608	3442.608	1019.348	-935.446	89.0	19.81	0.98	2.63	510.94	0.01
72	LS034	GA	Archer Daniels Midland Co - Vladosta	284.902	3412.901	1316.542	-915.144	70.7	17.68	1.45	12.37	355.38	8.57
73	LS035	GA	Archer Daniels Midland Co - Vladosta	284.902	3412.901	1316.542	-915.144	70.7	16.76	1.52	19.60	477.60	0.71
74	LS036	GA	Archer Daniels Midland Co - Vladosta	284.902	3412.901	1316.542	-915.144	70.7	24.38	0.76	0.24	422.05	0.42
75	LS037	GA	Coats & Clark Inc. - Albany	202.373	3498.009	1220.437	-845.076	68.6	18.29	1.83	5.22	449.83	3.64
76	LS038	GA	Cooper Tire & Rubber Co. - Albany	209.708	3496.604	1227.920	-845.218	53.0	9.14	0.51	7.16	422.05	0.69
77	LS039	GA	Cooper Tire & Rubber Co. - Albany	209.708	3496.604	1227.920	-845.218	53.0	19.81	1.07	13.96	425.38	31.60
78	LS041	GA	Great Southern Paper Co. Cedar Springs	109.611	3455.700	1135.921	-902.620	35.8	58.22	1.52	7.80	340.60	0.69
79	LS043	GA	Great Southern Paper Co. Cedar Springs	109.611	3455.700	1135.922	-902.609	36.0	58.22	1.52	7.86	343.49	0.69
80	LS044	GA	Great Southern Paper Co. Cedar Springs	109.611	3455.700	1135.906	-902.618	35.3	75.59	1.83	7.04	336.10	1.76
81	LS045	GA	Great Southern Paper Co. Cedar Springs	109.611	3455.700	1135.997	-902.351	42.6	24.99	1.83	9.66	354.60	2.32
82	LS046	GA	Great Southern Paper Co. Cedar Springs	109.611	3455.700	1135.981	-902.342	42.1	24.99	1.83	9.66	354.60	2.32
83	LS047	GA	Great Southern Paper Co. Cedar Springs	109.611	3455.700	1135.891	-902.608	34.9	60.96	3.66	27.61	436.16	54.41
84	LS048	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.964	-797.931	91.0	21.95	0.51	11.19	422.05	0.0003
85	LS049	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.910	-797.939	91.0	21.95	0.51	11.19	422.05	0.0003
86	LS050	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.914	-797.963	91.0	21.95	0.76	12.41	533.16	0.0004
87	LS051	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.866	-797.970	91.0	21.95	0.51	13.96	422.05	0.0003
88	LS052	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.828	-797.961	91.0	21.95	0.76	12.41	533.16	0.0004
89	LS053	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.786	-797.947	91.0	21.95	0.61	8.08	533.16	0.0001
90	LS054	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.744	-797.953	91.0	21.95	0.30	8.08	533.16	0.0001
91	LS055	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.684	-797.959	91.0	21.95	0.51	13.96	422.05	0.0003
92	LS056	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.683	-797.950	91.0	21.95	0.76	10.55	533.16	0.0004
93	LS057	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.699	-797.948	91.0	21.95	0.56	11.55	533.16	0.0003
94	LS058	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.699	-797.944	91.0	21.95	0.56	11.55	533.16	0.0003
95	LS059	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.712	-797.946	91.0	21.95	0.56	11.55	533.16	0.0003
96	LS060	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.712	-797.944	91.0	21.95	0.76	12.41	533.16	0.0004
97	LS061	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.681	-797.935	91.0	21.95	0.61	12.92	533.16	0.0005
98	LS062	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.681	-797.935	91.0	22.25	0.56	11.55	533.16	0.0003
99	LS063	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.678	-797.916	91.0	23.77	0.76	12.41	533.16	0.0005
100	LS064	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.678	-797.916	91.0	22.10	0.56	11.55	533.16	0.0003
101	LS065	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.694	-797.939	91.0	23.16	0.56	11.55	533.16	0.0003
102	LS066	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.799	-797.921	91.0	22.10	0.56	11.55	533.16	0.0003
103	LS067	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.694	-797.927	91.0	24.08	1.07	11.61	422.05	0.0005
104	LS068	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.699	-797.926	91.0	23.77	0.76	13.44	422.05	0.0005
105	LS069	GA	Masonite Corp. - Cordell	235.266	3540.082	1245.707	-797.937	91.0	23.77	0.76	13.44	422.05	0.0005
106	LS070	GA	Mullite Company of America - Plant 1 - Andersonville	204.204	3565.223	1210.823	-778.428	122.0	36.58	1.42	13.41	338.72	10.08
107	LS071	GA	Mullite Company of America - Plant 1 - Andersonville	204.204	3565.223	1210.823	-778.428	122.0	36.58	1.42	13.41	338.72	10.08
108	LS072	GA	Mullite Company of America - Plant 2 - Andersonville	206.258	3564.707	1212.937	-778.587	133.4	36.58	1.42	13.41	338.72	10.08
109	LS073	GA	Mullite Company of America - Plant 2 - Andersonville	206.258	3564.707	1212.937	-778.587	133.4	36.58	1.42	13.41	338.72	10.08
110	LS074	GA	Mullite Company of America - Plant 2 - Andersonville	206.258	3564.707	1212.937	-778.587	133.4	36.58	1.42	13.41	338.72	10.08
111	LS075	GA	Mullite Company of America - Plant 2 - Andersonville	206.258	3564.707	1212.937	-778.587	133.4	36.58	1.42	13.41	338.72	10.08
112	LS076	GA	Mullite Company of America - Plant 2 - Andersonville	206.258	3564.707	1212.937	-778.587	133.4	36.58	1.42	13.41	338.72	10.08
113	LS077	GA	Pecan Grove Generating LLC - Baconton	203.926	3475.215	1225.610	-865.320	69.2	45.72	4.62	33.28	410.94	12.59
114	LS078	GA	Pecan Grove Generating LLC - Baconton	203.926	3475.215	1225.963	-868.355	71.9	45.72	4.62	33.28	410.94	12.59
115	LS079	GA	Pecan Grove Generating LLC - Baconton	203.926	3475.215	1225.949	-868.316	71.5	22.86	0.61	24.26	449.83	0.03
116	LS081	GA	Procter & Gamble Paper Products Co. - Albany	204.949	3494.645	1223.396	-848.007	54.0	24.38	2.44	12.13	377.60	10.72

Table 10-4. PSD SO₂ Increment Consuming Emission Sources

(Continued, Page 3 of 3)

Model Identification		State	Facility Name	Stack Coordinates				Stack Parameters					SO ₂
				UTM		LLC		Elevation (m)	Height (m)	Diameter (m)	Velocity (m/s)	Temperature (K)	Emission
				Easting (km)	Northing (km)	Easting (km)	Northing (km)						Rate (g/s)
117	LS083	GA	Procter & mble Paper Products Co. - Albany	204.949	3494.645	1223.432	-848.003	54.0	24.38	2.44	12.13	377.60	3.21
118	LS084	GA	Procter & mble Paper Products Co. - Albany	204.949	3494.645	1223.487	-848.002	53.6	16.76	2.44	22.54	333.16	2.15
119	LS086	GA	Procter & mble Paper Products Co. - Albany	204.949	3494.645	1223.605	-847.982	53.3	24.38	2.44	12.13	377.60	12.61
120	LS088	GA	Procter & mble Paper Products Co. - Albany	204.949	3494.645	1223.645	-847.978	53.7	24.38	2.44	12.13	377.60	12.61
121	LS089	GA	Procter & mble Paper Products Co. - Albany	204.949	3494.645	1223.745	-847.962	54.0	30.02	2.59	10.72	377.60	0.03
122	LS090	GA	Procter & mble Paper Products Co. - Albany	204.949	3494.645	1223.827	-847.953	54.0	30.02	2.59	10.72	377.60	0.03
123	LS091	GA	Procter & mble Paper Products Co. - Albany	204.949	3494.645	1223.417	-847.864	54.8	42.67	1.62	16.13	337.05	8.42
124	LS092	GA	Procter & mble Paper Products Co. - Albany	204.949	3494.645	1223.416	-847.899	54.4	30.48	1.37	17.41	452.60	0.01
125	LS093	GA	Englehard Corp - Attapulgis	165.351	3405.333	1199.521	-942.957	60.0	36.58	0.91	11.28	422.05	3.53
126	LS094	GA	Englehard Corp - Attapulgis	165.351	3405.333	1199.521	-942.957	60.0	39.62	0.76	15.24	402.60	9.32
127	LS095	GA	Englehard Corp - Attapulgis	165.351	3405.333	1199.521	-942.957	60.0	30.48	1.83	1.74	533.16	18.06
128	LS096	GA	Miller Brewing Co - Albany	207.236	3498.536	1225.150	-843.730	73.5	60.66	2.04	23.04	438.16	176.65
129	LS097	GA	Miller Brewing Co - Albany	207.236	3498.536	1225.150	-843.730	73.5	35.05	1.22	15.36	463.16	4.98
130	LS098	GA	Miller Brewing Co - Albany	207.236	3498.536	1225.150	-843.730	73.5	4.42	0.46	15.24	422.05	0.87
131	LS099	GA	Georgia Pacific Corp - Albany	200.371	3500.305	1218.070	-843.149	63.0	9.14	0.58	27.43	505.38	0.29
132	LS100	GA	M&M/Mars - Albany	197.992	3494.700	1216.671	-849.088	58.3	8.84	0.94	12.50	505.38	11.45
133	LS101	GA	Marine Corps Logistics Base - Albany	207.883	3494.419	1226.439	-847.695	53.0	12.19	1.10	12.19	505.38	1.92
134	LS102	GA	Marine Corps Logistics Base - Albany	207.883	3494.419	1226.439	-847.695	53.0	15.85	1.22	14.63	292.05	0.23
135	LS103	GA	Reeves Construction Co. - Albany	197.801	3502.631	1215.137	-841.288	69.0	9.75	1.07	30.75	405.38	14.60
136	LS134	GA	Longleaf Energy Associates	112.035	3463.168	1137.079	-894.739	61.0	140.20	10.39	19.80	347.10	185.83

Note: All UTM coordinates have been converted to UTM Zone 17.

Sources: FDEP, 2006.
ECT, 2007.

Table 10-5. PSD SO₂ Increment Expanding Emission Sources

Model Identification				Stack Coordinates				Stack Parameters					SO ₂ Emission Rate (g/s)
				UTM		LLC		Elevation (meters)	Height (meters)	Diameter (meters)	Velocity (m/s)	Temperature (K)	
				Easting (km)	Northing (km)	Easting (km)	Northing (km)						
Number	Name	State	Facility Name	Easting (km)	Northing (km)	Easting (km)	Northing (km)	Elevation (meters)	Height (meters)	Diameter (meters)	Velocity (m/s)	Temperature (K)	Rate (g/s)
1	RB1B	Florida	Stone Container	54.680	3343.327	1100.328	-1022.846	71.00	0.00	1.96	26.82	428.00	15.50
2	RB2B	Florida	Stone Container	54.680	3343.327	1100.328	-1022.846	71.00	0.00	1.96	24.78	433.00	15.50
3	SDT1B	Florida	Stone Container	54.680	3343.327	1100.328	-1022.846	71.00	0.00	1.83	5.15	339.00	0.90
4	SDT2B	Florida	Stone Container	54.680	3343.327	1100.328	-1022.846	71.00	0.00	1.83	5.30	333.00	0.90
5	LK1B	Florida	Stone Container	54.680	3343.327	1100.328	-1022.846	18.60	0.00	2.44	10.24	344.00	0.40
6	BB3B	Florida	Stone Container	54.680	3343.327	1100.328	-1022.846	45.70	0.00	2.59	14.69	500.00	43.20
7	BB4B	Florida	Stone Container	54.680	3343.327	1100.328	-1022.846	45.70	0.00	2.24	18.47	516.00	68.80
8	PB45B	Florida	Stone Container	54.680	3343.327	1100.328	-1022.846	90.20	0.00	3.66	7.56	478.00	52.60
9	PB6B	Florida	Stone Container	54.680	3343.327	1100.328	-1022.846	73.50	0.00	2.44	10.85	494.00	66.00
10	TALPURD2	Florida	City of Tallahassee, Purdom	191.815	3340.914	1236.605	-1002.283	26.00	0.00	1.95	5.89	478.00	39.88
11	TALPURD3	Florida	City of Tallahassee, Purdom	191.815	3340.914	1236.605	-1002.283	26.00	0.00	1.95	5.89	478.00	39.88
12	TALPURD4	Florida	City of Tallahassee, Purdom	191.815	3340.914	1236.605	-1002.283	26.00	0.00	1.95	5.89	478.00	39.88
13	TALPURD5	Florida	City of Tallahassee, Purdom	191.815	3340.914	1236.605	-1002.283	38.10	0.00	3.96	7.23	447.00	104.04
14	TALPURD6	Florida	City of Tallahassee, Purdom	191.815	3340.914	1236.605	-1002.283	38.10	0.00	3.96	7.23	447.00	104.04
15	TALPURD7S	Florida	City of Tallahassee, Purdom	191.815	3340.914	1236.605	-1002.283	54.90	0.00	2.74	14.44	422.00	68.92
16	TALPURGT	Florida	City of Tallahassee, Purdom	191.815	3340.914	1236.605	-1002.283	11.60	0.00	3.05	25.56	744.00	10.29
17	TALHOPK1	Florida	City of Tallahassee, Hopkins	173.216	3373.756	1212.634	-972.888	61.00	40.20	3.35	21.11	400.00	227.59
18	FCPLKSDT	Florida	Florida Rock Cement	82.806	3305.630	1134.456	-1055.536	30.50	3.00	2.38	2.25	367.70	3.10
19	FCPRB567	Florida	Florida Rock Cement	82.806	3305.630	1134.456	-1055.536	38.10	3.00	2.56	9.10	394.30	86.61
20	ST12	Florida	Ameristeel	405.800	3350.300	1447.085	-956.260	35.05	26.20	3.05	19.76	383.20	1.28
21	ST34	Florida	Ameristeel	405.800	3350.300	1447.085	-956.260	35.05	26.20	3.05	20.70	383.20	0.14
22	REHEAT	Florida	Ameristeel	405.800	3350.300	1447.085	-956.260	48.77	26.20	2.10	5.93	755.40	0.01
23	SULACA&B	Florida	Potash White Springs	328.300	3368.800	1367.090	-951.353	61.00	24.00	1.80	15.50	350.00	304.50
24	EULACC&D	Florida	Potash White Springs	328.300	3368.800	1367.090	-951.353	45.70	24.00	1.59	28.70	356.00	75.60
31	FPL1E	Florida	Florida Power & Light, Palatka	442.800	3277.600	1493.370	-1024.470	24.40	45.69	3.96	9.51	408.15	257.03
32	GP1E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	76.17	3.66	8.81	359.98	6.21
33	GP2E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	76.17	3.66	8.81	371.98	8.88
34	GP3E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	70.07	3.66	16.86	418.43	35.00
35	GP4E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	72.88	2.74	15.97	519.98	161.00
36	GP5E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	72.88	3.05	10.52	476.98	121.00
37	GP6E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	72.88	3.05	10.52	476.98	332.09
38	GP7E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	40.48	3.35	7.28	371.98	8.58
39	GP8E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	37.19	1.22	14.54	476.98	45.20
40	GP9E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	45.38	1.22	16.46	350.98	1.40
41	GP10E	Florida	Georgia Pacific, Palatka	434.000	3283.400	1483.630	-1020.220	24.40	15.21	1.22	5.24	400.98	2.36
25	LS040	Georgia	Great Southern Paper Co., Cedar Springs, Georgia	109.611	3455.700	1135.921	-902.620	49.07	35.80	1.22	7.80	340.60	0.63
26	LS042	Georgia	Great Southern Paper Co., Cedar Springs, Georgia	109.611	3455.700	1135.922	-902.609	49.07	36.00	1.52	7.86	343.49	0.69
27	LS080	Georgia	Procter & Gamble Paper Products Co., Albany, Georgia	204.949	3494.645	1223.398	-847.999	20.73	54.00	3.96	3.24	358.72	5.41
28	LS082	Georgia	Procter & Gamble Paper Products Co., Albany, Georgia	204.949	3494.645	1223.436	-847.995	22.86	54.00	3.96	3.24	358.72	5.41
29	LS085	Georgia	Procter & Gamble Paper Products Co., Albany, Georgia	204.949	3494.645	1223.611	-847.985	32.00	53.30	2.44	20.35	353.72	6.77
30	LS087	Georgia	Procter & Gamble Paper Products Co., Albany, Georgia	204.949	3494.645	1223.649	-847.970	32.00	53.70	2.44	20.35	353.72	8.69

Note: All UTM coordinates have been converted to UTM Zone 17.

Sources: FDEP, 2006.
ECT, 2007.

Table 10-6. TEC Main Boiler—Summary of PSD Class I Cumulative SO₂ Air Quality Impacts

Pollutant	Year of Meteorology	Averaging Period	Class I Area Impact		
			St. Marks NWA (µg/m ³)	Okeefenokee NWA (µg/m ³)	Bradwell Bay NWA (µg/m ³)
SO ₂	2001	24-Hour (HSH)	2.2	N/A	3.6
	2002		2.8	2.6	3.5
	2003		2.3	2.9	2.8
	Maximum		2.8	2.9	3.6
	PSD Class I Increment		5.0	5.0	5.0
% of PSD Class I Increment			55.1	57.3	71.2
SO ₂	2001	3-Hour (HSH)	9.4	N/A	N/A
	2002		8.4	N/A	15.0
	2003		10.0	N/A	7.8
	Maximum		10.0	N/A	15.0
	PSD Class I Increment		25.0	25.0	25.0
% of PSD Class I Increment			39.9	N/A	59.9

N/A = not applicable.

HSH = highest, second highest.

Source: ECT, 2007.

Table 10-7. Summary of PSD Class I Air Quality Impacts—Nitrogen and Sulfur Deposition

Pollutant	Year of Meteorology	Averaging Period	Class I Area Impact									
			St. Marks NWA		Chassahowitzka NWA		Okefenokee NWA		Bradwell Bay NWA		Wolf Island NWA	
			($\mu\text{g}/\text{m}^2/\text{s}$)	(kg/ha/yr)	($\mu\text{g}/\text{m}^2/\text{s}$)	(kg/ha/yr)	($\mu\text{g}/\text{m}^2/\text{s}$)	(kg/ha/yr)	($\mu\text{g}/\text{m}^2/\text{s}$)	(kg/ha/yr)	($\mu\text{g}/\text{m}^3$)	(kg/ha/yr)
Total wet and dry nitrogen deposition	2001	Annual	0.000031	0.0098	0.000005	0.0016	0.000023	0.0071	0.000018	0.0057	0.000008	0.0026
	2002		0.000048	0.0152	0.000006	0.0018	0.000025	0.0080	0.000023	0.0072	0.000005	0.0015
	2003		0.000041	0.0130	0.000003	0.0010	0.000028	0.0087	0.000017	0.0054	0.000010	0.0033
	Maximum		0.000048	0.0152	0.000006	0.0018	0.000028	0.0087	0.000023	0.0072	0.000010	0.0033
FLM DAT				0.01		0.01		0.01		0.01		0.01
% of FLM DAT SIL				152.5		18.3		87.0		71.7		33.0
Exceed FLM DAT				Yes		No		No		No		No
Total wet and dry sulfur deposition	2001	Annual	0.000074	0.0233	0.000012	0.0038	0.000047	0.0149	0.000036	0.0113	0.000016	0.0049
	2002		0.000112	0.0354	0.000015	0.0048	0.000052	0.0163	0.000045	0.0141	0.000011	0.0033
	2003		0.000099	0.0311	0.000009	0.0030	0.000054	0.0169	0.000036	0.0112	0.000020	0.0063
	Maximum		0.000112	0.0354	0.000015	0.0048	0.000054	0.0169	0.000045	0.0141	0.000020	0.0063
FLM DAT				0.01		0.01		0.01		0.01		0.01
% of FLM DAT SIL				354.4		47.6		169.0		141.4		63.4
Exceed FLM DAT				Yes		No		Yes		Yes		No

Source: ECT, 2007.

10.7.4 REGIONAL HAZE

Assessment of TEC regional haze impacts was conducted for the St. Marks and Chassahowitzka NWAs in Florida and the Okefenokee and Wolf Island NWAs in Georgia. An assessment of regional haze impacts was not conducted for the Bradwell Bay NWA since this Class I area is not among the mandatory Federal Class I areas identified in 40 CFR 81, Subpart D, §81.407 as being subject to visibility protection.

The regional haze assessments employed three analytical procedures and the EPA-approved version of the CALPUFF modeling suite. The analytical procedures included:

- Procedure 1—FLAG, NPS, and IWAQM recommended procedures including use of background extinction computation Method 2 (compute extinction from speciated PM measurements and hourly relative humidity adjustment applied to observed and modeled sulfate and nitrate), Class I-specific Raleigh scattering extinction, and the current IMPROVE light extinction algorithm.
- Procedure 2—Procedure 1 procedures with the new IMPROVE light extinction algorithm.
- Procedure 3—Procedure 2 procedures using background extinction computation Method 6 (compute extinction from speciated PM measurements and FLAG RH adjustment factor applied to observed and modeled sulfate and nitrate).

The new IMPROVE light extinction algorithm provides a better correspondence between the measured visibility and that calculated from PM component concentrations. Technical improvements contained in the new IMPROVE algorithm include:

- Extinction efficiencies of sulfates, nitrates, and organics have been changed and are functions of their concentrations. The extinction efficiencies of sulfate and nitrate are no longer identical, although the new hygroscopic scattering enhancement factors applied to them are the same.
- The concentration of particulate organic matter is taken to be 1.8 times that of the measured organic carbon concentration.

- The contribution of fine sea salt to light extinction has been added, and is accompanied by its own hygroscopic scattering enhancement factor, $f_{ss}(RH)$.
- The light scattering by air itself (Rayleigh scattering) now varies with site elevation.
- The light absorption by NO_2 gas has been added.

The analytical procedures described for assessing regional haze compare project visibility impacts to *natural* background levels that would occur in the absence of all anthropogenic activities. In addition, the methods do not consider the effects of natural visibility impairment caused by rain or fog events. During such natural visibility impairment events, much lower visibility will occur compared to the assumed natural background level. Accordingly, meteorological conditions during the days when TEC regional haze impacts were projected to exceed the FLAG recommended significant level of a greater than 5-percent increase in beta extinction (B_{ext}) were evaluated to determine if natural visibility impairment was occurring. Weather data evaluated included surface data from nearby monitoring stations, local climatological data (LCD) summarizing surface data at nearby airports monitoring stations, Next Generation Radar (NEXRAD) national mosaic reflectivity images, and hourly precipitation data reports. For the 3-year (2001 through 2003) period of meteorological data (total of 1,094 days) used in the TEC regional haze assessment and for the four Class I areas evaluated, there were a total of 27 days, or 2.5 percent of the 3-year meteorological period, that TEC was predicted to have visibility impacts greater than a 5-percent change in B_{ext} . Appendix D provides an analysis of natural impairment for each day evaluated.

The results of the TEC regional haze assessments for each Class I area evaluated are provided in the following subsections. Results are provided for the highest 24-hour average impact as well as the 98th percentile of the 24-hour average impacts (equivalent to the eighth highest 24-hour average impact at any receptor). The 24-hour average 98th percentile impact is the metric used for the assessment of regional haze impacts under the BART provisions of the CAVR. As stated in the preamble to the final BART rules issued on July 5, 2005, EPA agreed that the maximum 24-hour visibility impacts could be the result of unusual meteorological conditions. For this reason, the 98th percentile value was

selected to eliminate unusual and infrequent weather conditions from unduly influencing visibility analyses. As further justification for selecting the 98th percentile value, EPA also stated that the simplified chemistry in the CALPUFF model tends to magnify the actual visibility effects of a source. Accordingly, use of the 98th percentile (eighth highest 24-hour average impact for any receptor), rather than the highest 24-hour average impact, is considered to be the most appropriate approach for assessing visibility impacts at Class I areas.

10.7.4.1 St. Marks NWA

Table 10-8 provides a summary of TEC visibility impacts at the St. Marks NWA. This table shows the 24-hour average maximum and 98th percentile changes in B_{ext} and the number of days with a change in B_{ext} greater than 5 percent.

Over the 3-year period of meteorological data, there are only 8 days (excluding days of natural impairment) that are projected to exceed a 5-percent change in B_{ext} or 0.7 percent of the time using the FLAG procedures and new IMPROVE algorithm.

For 2002 year meteorology, a greater than 10-percent change in B_{ext} was predicted to occur on 1 day: January 28th. Based on a review of reported weather data for this day at the Perry Foley Airport (15 hours of precipitation), Tallahassee Regional Airport (12 hours of reported fog and/or mist with 8 hours of 100-percent relative humidity), Apalachicola Municipal Airport (19 hours of fog and/or mist, 16 hours of visibility less than 1 statute mile, and 12 hours of 100-percent relative humidity), the Panhandle region of Florida (including the St. Marks NWA) experienced wide-spread fog, mist, and rain throughout the day resulting in natural visibility impairment.

10.7.4.2 Chassahowitzka NWA

Table 10-9 provides a summary of TEC visibility impacts at the Chassahowitzka NWA. Visibility impacts are all less than a 5-percent change in B_{ext} using the FLAG recommended procedures.

Table 10-8. St. Marks NWA Regional Haze Impacts

Metric	Units	Year	Analytical Procedure		
			1	2	3
Maximum ΔB_{ext}	%	2001	6.4 (4.9)	6.1 (4.8)	6.5
		2002	12.3 (8.7)	11.9 (8.5)	7.2
		2003	8.6 (6.3)	8.0 (6.2)	6.0 (6.1)
98 th percentile ΔB_{ext} (8 th highest day - all receptors)	%	2001	4.5	4.5	4.2
		2002	5.7	5.4	4.6
		2003	4.6	4.5	4.4
Days with $\Delta B_{\text{ext}} > 10\%$	—	2001	0	0	0
		2002	1 (0)	1 (0)	0
		2003	0	0	0
Days with $\Delta B_{\text{ext}} > 5\%$	—	2001	5 (0)	5 (0)	4 (2)
		2002	10 (5)	9 (5)	5 (3)
		2003	6 (3)	6 (3)	4 (2)

() - excluding days of natural visibility impairment.

Δ = delta (i.e., change in B_{ext} compared to natural background).

Procedure 1—FLAG options, RH Method 2, Rayleigh = 11 inverse megameters, Old IMPROVE algorithm.

Procedure 2—FLAG options, RH Method 2, Rayleigh = 11 inverse megameters, New IMPROVE algorithm, Sea Salt = 0.03 $\mu\text{g}/\text{m}^3$.

Procedure 3—RH Method 6, Rayleigh = 11 inverse megameters, New IMPROVE Algorithm, Sea Salt = 0.03 $\mu\text{g}/\text{m}^3$.

Source: ECT, 2007.

Table 10-9. Chassahowitzka NWA Regional Haze Impacts

Metric	Units	Year	Analytical Procedure		
			1	2	3
Maximum ΔB_{ext}	%	2001	4.7	4.1	5.6
		2002	2.8	2.5	2.0
		2003	3.8	3.5	4.3
98 th percentile ΔB_{ext} (8 th highest day - all receptors)	%	2001	2.5	2.2	1.6
		2002	1.9	1.7	1.5
		2003	2.1	2.0	2.1
Days with $\Delta B_{\text{ext}} > 10\%$	—	2001	0	0	0
		2002	0	0	0
		2003	0	0	0
Days with $\Delta B_{\text{ext}} > 5\%$	—	2001	0	0	1
		2002	0	0	0
		2003	0	0	0

() - excluding days of natural visibility impairment

Δ = delta; i.e., change in B_{ext} compared to natural background.

Procedure 1 - FLAG options, RH Method 2, Rayleigh = 11 inverse megameters, Old IMPROVE algorithm.

Procedure 2 - FLAG options, RH Method 2, Rayleigh = 11 inverse megameters, New IMPROVE algorithm, Sea Salt = 0.08 $\mu\text{g}/\text{m}^3$.

Procedure 3 - RH Method 6, Rayleigh = 11 inverse megameters, New IMPROVE Algorithm, Sea Salt = 0.08 $\mu\text{g}/\text{m}^3$.

Source: ECT, 2007.

10.7.4.3 Okefenokee NWA

Table 10-10 provides a summary of TEC visibility impacts at the Okefenokee NWA. Excluding natural visibility impairment, there are 2 days over the 3-year period of meteorological data (i.e., 2 days out of 1,094 days, or 0.18 percent of the time) with a TEC visibility impact above a 5-percent change in B_{ext} using the FLAG recommended procedures and new IMPROVE algorithm. All 98th percentile 24-hour average visibility impacts are less than a 5-percent change in B_{ext} .

10.7.4.4 Wolf Island NWA

Table 10-11 provides a summary of TEC visibility impacts at the Wolf Island NWA. As shown in this table, TEC visibility impacts are all less than a change of 5-percent in B_{ext} using the FLAG recommended procedures.

10.7.4.5 Conclusions

The TEC regional haze impacts are considered acceptable for the following reasons:

- Frequency of occurrence of TEC visibility impacts exceeding a 5-percent change in B_{ext} is low. For the 3-year period of meteorological data evaluated, TEC visibility impacts at the St. Marks NWA were projected to exceed a 5-percent change in B_{ext} for only 20 days or 1.8 percent of the time using the FLAG procedures and new IMPROVE algorithm. Excluding natural visibility impairment, TEC visibility impacts at the St. Marks NWA were projected to exceed a 5-percent change in B_{ext} for only 8 days or 0.7 percent of the time. Frequency of TEC visibility impacts above a 5-percent change in B_{ext} at the Okefenokee NWA over the 3-year period were also low—a total of 4 days and only 2 days excluding natural visibility impairment. TEC visibility impacts at the Chassahowitzka and Wolf Island NWAs were all below a 5-percent change in B_{ext} . Figure 10-3 summarizes TEC visibility impacts at the St. Marks NWA excluding days of natural visibility impairment.
- 24-hour average 98th percentile visibility impact was projected to be slightly above a 5-percent change in B_{ext} for the St. Marks NWA during 1 year of meteorology (i.e., a 5.4-percent change during 2002). The 24-hour average

Table 10-10. Okefenokee NWA Regional Haze Impacts

Metric	Units	Year	Analytical Procedure		
			1	2	3
Maximum ΔB_{ext}	%	2001	6.6	5.8	4.0
		2002	7.2 (5.3)	6.5 (5.0)	6.1 (3.7)
		2003	10.7	9.9	4.4
98 th percentile ΔB_{ext} (8 th highest day - all receptors)	%	2001	3.0	2.7	2.7
		2002	3.3	3.0	2.7
		2003	2.8	2.6	2.2
Days with $\Delta B_{\text{ext}} > 10\%$	—	2001	0	0	0
		2002	0	0	0
		2003	1	0	0
Days with $\Delta B_{\text{ext}} > 5\%$	—	2001	1	1	0
		2002	2 (1)	1 (0)	1 (0)
		2003	3 (1)	2 (1)	0

() - excluding days of natural visibility impairment

Δ = delta; i.e., change in B_{ext} compared to natural background.

Procedure 1 - FLAG options, RH Method 2, Rayleigh = 11 inverse megameters, Old IMPROVE algorithm.

Procedure 2 - FLAG options, RH Method 2, Rayleigh = 11 inverse megameters, New IMPROVE algorithm, Sea Salt = 0.09 $\mu\text{g}/\text{m}^3$.

Procedure 3 - RH Method 6, Rayleigh = 11 inverse megameters, New IMPROVE Algorithm, Sea Salt = 0.09 $\mu\text{g}/\text{m}^3$.

Source: ECT, 2007.

Table 10-11. Wolf Island NWA Regional Haze Impacts

Metric	Units	Year	Analytical Procedure		
			1	2	3
Maximum ΔB_{ext}	%	2001	2.7	2.2	1.3
		2002	3.0	2.5	1.7
		2003	3.7	3.2	2.0
98 th percentile ΔB_{ext} (8 th highest day - all receptors)	%	2001	1.4	1.1	0.8
		2002	1.5	1.3	1.2
		2003	1.6	1.4	1.2
Days with $\Delta B_{\text{ext}} > 10\%$	—	2001	0	0	0
		2002	0	0	0
		2003	0	0	0
Days with $\Delta B_{\text{ext}} > 5\%$	—	2001	0	0	0
		2002	0	0	0
		2003	0	0	0

() - excluding days of natural visibility impairment

Δ = delta; i.e., change in B_{ext} compared to natural background.

Procedure 1 - FLAG options, RH Method 2, Rayleigh = 11 inverse megameters, Old IMPROVE algorithm.

Procedure 2 - FLAG options, RH Method 2, Rayleigh = 11 inverse megameters, New IMPROVE algorithm, Sea Salt = 0.09 $\mu\text{g}/\text{m}^3$.

Procedure 3 - RH Method 6, Rayleigh = 11 inverse megameters, New IMPROVE Algorithm, Sea Salt = 0.09 $\mu\text{g}/\text{m}^3$.

Source: ECT, 2007.

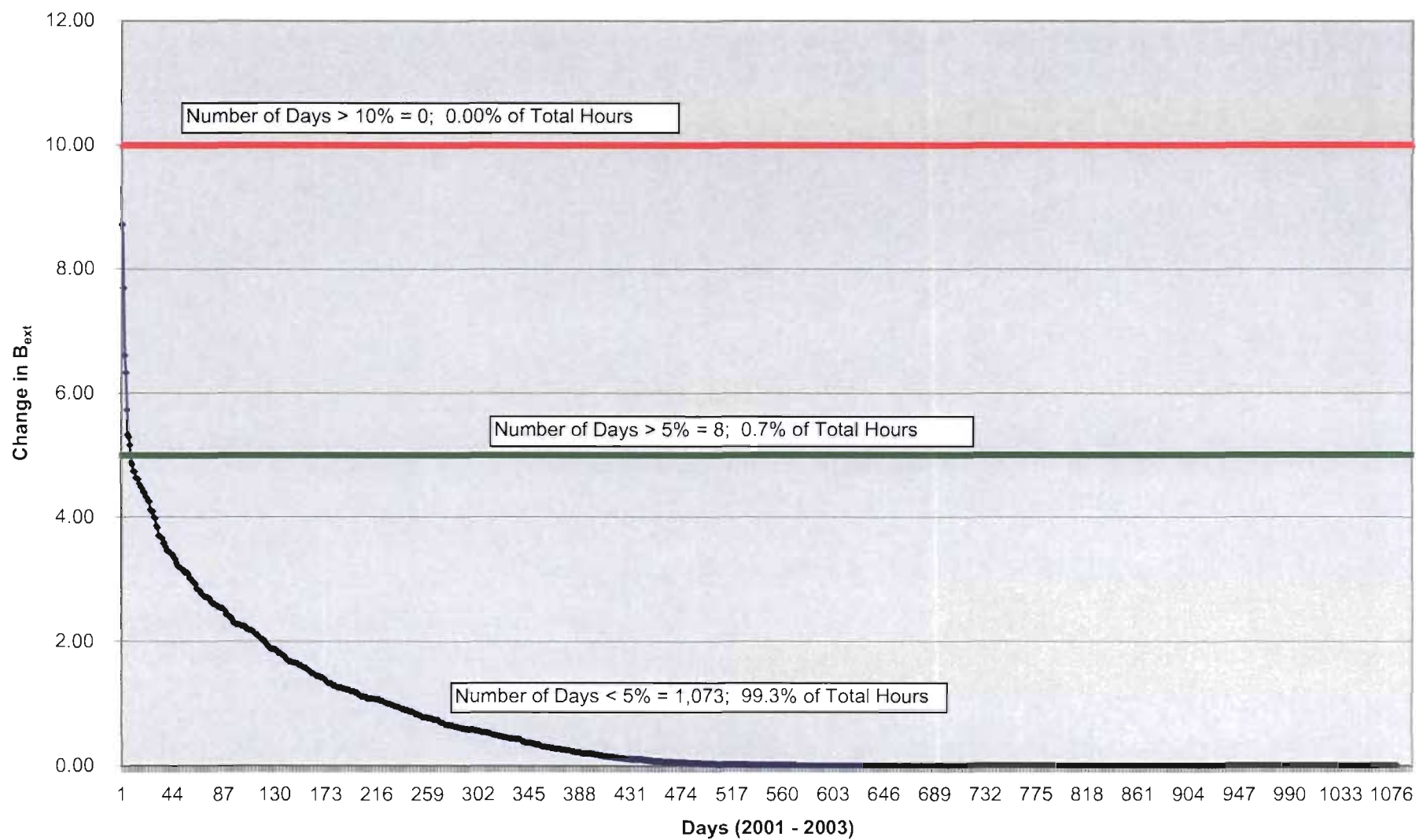


FIGURE 10-3.

TEC VISIBILITY IMPACTS—ST. MARKS NWA

Source: ECT, 2005.

98th percentile visibility impacts were projected to be less than a 5-percent change in B_{ext} for the St. Marks NWA for 2001 and 2003 and for all years for the other three Class I areas evaluated. Use of the 98th percentile impacts is consistent with the CAVR and is considered the most appropriate metric for evaluating visibility impacts since it is intended to exclude unusual and infrequent meteorological conditions.

- The 5-percent FLM guideline is half of the level that is perceptible (i.e., increases in B_{ext} above 10 percent are considered to be perceptible at the furthest extent of the visual range).
- The regional haze analysis compares project impacts with natural background (i.e., a theoretical background that would occur in the absence of all anthropogenic activities). This results in a natural background B_{ext} of approximately 25 inverse megameters and a visual range of 155 miles for the St. Marks NWA. Other than nighttime celestial objects, there are no line-of-sight vistas in the coastal St. Marks NWA that are near this visual range. For example, the theoretical line-of-sight for a 6-ft-tall person on the shoreline of the Gulf of Mexico is 3.2 miles due to the curvature of the earth.
- There will be significant actual reductions in actual Florida power plant NO_x and SO_2 emissions due to implementation of CAIR. For example, actual NO_x and SO_2 emissions from Unit 2 located at the Gainesville Regional Utilities (GRU) Deerhaven Generating Station are expected to be reduced by 3,262 and 7,139 tpy, respectively, due to the installation of emission control systems. The GRU Deerhaven Generating Station is located approximately 110 km east of TEC. In comparison, TEC potential NO_x and SO_2 emissions are 1,653 and 1,310 tpy, respectively. Accordingly, the actual emission reductions from just one existing Florida power plant will more than offset the emission increases associated with TEC (i.e., actual emission reductions from this one existing power plant will be roughly twice the potential TEC NO_x emissions and more than 5 times the potential TEC SO_2 emissions). Greater emission reductions will occur due to CAIR at existing Florida power plants located to the west and south of TEC. Statewide, CAIR is expected to reduce actual 2003 Florida power plant SO_2 emissions by 54 percent in

Phase 1 (a reduction in actual SO₂ emissions of 257,000 tpy) and actual NO_x emissions by 73 percent (a reduction in actual NO_x emissions of 184,000 tpy). The Phase 1 CAIR actual emission reductions will occur prior to the commencement of TEC operation. Improvement in regional haze would be expected to occur throughout Florida due to these substantial reductions in actual power plant emissions.

APPENDIX A

EMISSION RATE CALCULATIONS

Appendix A - Taylor Energy Center Emission Rate Calculations

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Source: ECT, 2007.

**Table A-1. Taylor Energy Center
Annual Criteria Pollutant Emission Rate Summary**

Criteria Pollutant	Potential Annual Emissions (tpy)						Project Totals
	Main Boiler	Auxiliary Boiler	Generator Diesel Engine	Fire Water Pump Diesel Engine	Cooling Tower	Material Handling	
NO _x	1,637.0	14.8	1.04	0.09	N/A	N/A	1,652.9
CO	4,911.1	13.1	0.61	0.12	N/A	N/A	4,924.9
VOC	117.9	0.9	0.07	0.05	N/A	N/A	118.9
SO ₂	1,309.6	0.3	Neg.	Neg.	N/A	N/A	1,309.9
PM ₁₀	803.0	3.8	0.03	0.01	1.1	12.3	820.2
Pb	0.13	Neg.	Neg.	Neg.	N/A	N/A	0.13

N/A - not applicable

Neg. - negligible

Sources: ECT, 2007.

S&L, 2007.

**Table A-2. Taylor Energy Center
Annual Hazardous Air Pollutant Emission Rate Summary**

Hazardous Air Pollutant	Potential Annual Emissions (tpy)				Project Totals
	Main Boiler	Auxiliary Boiler	Generator Diesel Engine	Fire Water Pump Diesel Engine	
<u>Organic HAPS</u>					
1,1,1-Trichloroethane	0.0330	2.83E-04			0.0333
2,4-Dinitrotoluene	0.0005				0.0005
2-Chloroacetophenone	0.0116				0.0116
Acetaldehyde	0.0116		6.72E-04	1.23E-04	0.0124
Acetophenome	0.0248				0.0248
Acrolein	0.4789		8.10E-05	1.48E-05	0.4790
Benzene	2.1466	2.57E-04	8.17E-04	1.49E-04	2.1479
Benzyl Chloride	1.1559				1.1559
Bis(2-ethylhexyl)phthalate (DEHP)	0.1205				0.1205
Bromoform	0.0644				0.0644
Carbon Disulfide	0.2147				0.2147
Chlorobenzene	0.0363				0.0363
Chloroform	0.0974				0.0974
Cumene	0.0088				0.0088
Cyanide	4.1282				4.1282
Dibenzofurans (Total PCDD/PCDF)	0.0000029				0.0000
Dimethyl Sulfate	0.0793				0.0793
Ethyl Benzene	0.1552	7.63E-05			0.1553
Ethyl Chloride	0.0694				0.0694
Ethylene Dibromide	0.0020				0.0020
Ethylene Dichloride	0.0661				0.0661
Formaldehyde	0.3963	3.96E-02	1.03E-03	1.89E-04	0.4371
Hexane	0.1106				0.1106
Isophorone	0.9577				0.9577
Methyl Bromide	0.2642				0.2642
Methyl Chloride	0.8752				0.8752
Methyl Ethyl Ketone	0.6440				0.6440
Methyl Hydrazine	0.2807				0.2807
Methyl Methacrylate	0.0330				0.0330
Methyl tert butyl ether	0.0578				0.0578
Methylene Chloride	0.4789				0.4789
Naphthalene	0.0215	1.35E-03			0.0228
Phenol	0.0264				0.0264
Polycyclic Aromatic Hydrocarbons	0.0315	7.26E-05	1.47E-04	2.69E-05	0.0317
Propionaldehyde	0.6275				0.6275
Styrene	0.0413				0.0413
Tetrachloroethylene	0.0710				0.0710
Toluene	0.3963	7.43E-03	3.58E-04	6.54E-05	0.4042
Vinyl Acetate	0.0125				0.0125
Xylenes	0.0611	1.31E-04	2.50E-04	4.56E-05	0.0615
<u>Acid Gases</u>					
HCl	147.7453	4.16E-01			148.1613
HF	15.2995	4.47E-02			15.3442
<u>Metallic HAPS</u>					
Antimony (Sb)	0.0093				0.0093
Arsenic (As)	0.1811	6.57E-04			0.1818
Beryllium (Be)	0.0318	4.93E-04			0.0323
Cadmium (Cd)	0.0055	4.93E-04			0.0060
Chromium (Cr)	0.1682	4.93E-04			0.1687
Cobalt (Co)	0.0690				0.0690
Lead (Pb)	0.1270	1.48E-03			0.1285
Manganese (Mn)	0.9833	9.86E-04			0.9843
Mercury (Hg)	0.0291	4.93E-04			0.0296
Nickel (Ni)	1.2177	4.93E-04			1.2182
Selenium (Se)	0.9383	2.46E-03			0.9408
Vanadium (V)	2.6763				2.6763
					0.0000
Totals	183.7740	0.5180	0.0034	0.0004	184.2956

Sources: ECT, 2007.
S&L, 2007.

**Table A-3. Taylor Energy Center
Main Solid Fuel-Fired Boiler - Criteria Pollutant Emission Rate**

Pollutant	Averaging Period	Units	Fuel Type					Maximums
			Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Operating Hours	Annual	hrs/yr	8,760	8,760	8,760	8,760	8,760	8,760
Output (100% Load)	Max. Hourly	MW, gross	818.5	818.5	818.5	818.5	818.5	818.5
Heat Input (100% Load)	Max. Hourly	10 ⁶ Btu/hr (HHV)	7,333	7,432	7,475	7,383	7,320	7,475
NO _x	30-day and Annual	lb / 10 ⁶ Btu	0.050	0.050	0.050	0.050	0.050	0.050
		lb / MWh	0.448	0.454	0.457	0.451	0.447	0.457
		tpy	1,605.9	1,627.6	1,637.0	1,616.9	1,603.1	1,637
		lb/hr	366.7	371.6	373.8	369.2	366.0	373.8
		g/s	46.2	46.8	47.1	46.5	46.1	47.09
	24-hr	lb / 10 ⁶ Btu	0.050	0.050	0.050	0.050	0.050	0.050
		lb / MWh	0.448	0.454	0.457	0.451	0.447	0.457
		lb/hr	366.7	371.6	373.8	369.2	366.0	373.8
		g/s	46.2	46.8	47.1	46.5	46.1	47.09
	30-day and Annual	lb / 10 ⁶ Btu	0.040	0.040	0.040	0.040	0.040	0.040
		lb / MWh	0.358	0.363	0.365	0.361	0.358	0.365
		tpy	1,284.7	1,302.1	1,309.6	1,293.5	1,282.5	1,310
		lb/hr	293.3	297.3	299.0	295.3	292.8	299.0
		g/s	37.0	37.5	37.7	37.2	36.9	37.67
SO ₂	24-hr	lb / 10 ⁶ Btu	0.055	0.055	0.055	0.055	0.055	0.055
		lb / MWh	0.493	0.499	0.502	0.496	0.492	0.502
		lb/hr	403.3	408.8	411.1	406.1	402.6	411.1
		g/s	50.8	51.5	51.8	51.2	50.7	51.80
	3-hr	lb / 10 ⁶ Btu	0.070	0.070	0.070	0.070	0.070	0.070
		lb / MWh	0.627	0.636	0.639	0.631	0.626	0.639
		lb/hr	513.3	520.2	523.3	516.8	512.4	523.3
		g/s	64.7	65.5	65.9	65.1	64.6	65.93
	1-hr, 8-hr and Annual	lb / 10 ⁶ Btu	0.150	0.150	0.150	0.150	0.150	0.150
		lb / MWh	1.344	1.362	1.370	1.353	1.341	1.370
		tpy	4,817.8	4,882.8	4,911.1	4,850.6	4,809.2	4,911
		lb/hr	1,100.0	1,114.8	1,121.3	1,107.5	1,098.0	1,121.3
		g/s	138.6	140.5	141.3	139.5	138.3	141.28
CO	1-hr, 8-hr and Annual	lb / 10 ⁶ Btu	0.150	0.150	0.150	0.150	0.150	0.150
		lb / MWh	1.344	1.362	1.370	1.353	1.341	1.370
		tpy	4,817.8	4,882.8	4,911.1	4,850.6	4,809.2	4,911
		lb/hr	1,100.0	1,114.8	1,121.3	1,107.5	1,098.0	1,121.3
		g/s	138.6	140.5	141.3	139.5	138.3	141.28
VOC	3-hr and Annual	lb / 10 ⁶ Btu	0.0029	0.0033	0.0036	0.0031	0.0029	0.0036
		lb / MWh	0.0260	0.0300	0.0329	0.0280	0.0259	0.0329
		tpy	93.1	107.4	117.9	100.2	93.0	117.9
		lb/hr	21.3	24.5	26.9	22.9	21.2	26.9
		g/s	2.7	3.1	3.4	2.9	2.7	3.39

CA - Central Appalachian
PRB - Power River Basin
LA - Latin America
Petcoke - Petroleum Coke

Sources: ECT, 2007.
S&L, 2007.

Table A-3. Taylor Energy Center (continued, Page 2 of 2)
Main Solid Fuel-Fired Boiler - Criteria Pollutant Emission Rate

Pollutant	Averaging Period	Units	Fuel Type					Maximums
			Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Operating Hours	Annual	hrs/yr	8,760	8,760	8,760	8,760	8,760	8,760
Output (100% Load)	Max. Hourly	MW, gross	818.5	818.5	818.5	818.5	818.5	818.5
Heat Input (100% Load)	Max. Hourly	10 ⁶ Btu/hr (HHV)	7,333	7,432	7,475	7,383	7,320	7,475
PM ₁₀ (filterable)	30-day, 24-hr and Annual	lb / 10 ⁹ Btu	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130
		lb / MWh	0.1165	0.1180	0.1187	0.1173	0.1163	0.1187
		tpy	417.5	423.2	425.6	420.4	416.8	425.6
		lb/hr	95.3	96.6	97.2	96.0	95.2	97.2
		g/s	12.0	12.2	12.2	12.1	12.0	12.24
PM ₁₀ (condensable)	30-day, 24-hr and Annual	lb / 10 ⁹ Btu	0.0120	0.0095	0.0113	0.0110	0.0119	0.0120
		lb / MWh	0.1075	0.0863	0.1032	0.0992	0.1064	0.1075
		tpy	385.4	309.2	370.0	355.7	381.5	385.4
		lb/hr	88.0	70.6	84.5	81.2	87.1	88.0
		g/s	11.1	8.9	10.6	10.2	11.0	11.09
PM ₁₀ (total)	30-day, 24-hr and Annual	lb / 10 ⁹ Btu	0.0250	0.0225	0.0243	0.0240	0.0249	0.0250
		lb / MWh	0.2240	0.2043	0.2219	0.2165	0.2227	0.2240
		tpy	803.0	732.4	795.6	776.1	798.3	803.0
		lb/hr	183.3	167.2	181.6	177.2	182.3	183.3
		g/s	23.1	21.1	22.9	22.3	23.0	23.10
Pb	1-hr and Annual	lb / 10 ⁶ Btu	0.0000023	N/A	0.0000039	N/A	0.0000023	0.0000039
		lb / MWh	0.000021		0.000035		0.000021	0.000035
		tpy	0.074		0.127		0.074	0.13
		lb/hr	0.0170		0.0290		0.0170	0.029
		g/s	0.0021		0.0037		0.0021	0.0037

CA - Central Appalachian
PRB - Power River Basin
LA - Latin America
Petcoke - Petroleum Coke

Sources: ECT, 2007.
S&L, 2007.

**Table A-4. Taylor Energy Center
Main Solid Fuel-Fired Boiler - Non-Criteria Pollutant Emission Rates**

Pollutant	Averaging Period	Units	Fuel Type					Maximums
			Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Output	Max.	MW, gross	818.5	818.5	818.5	818.5	818.5	818.5
Heat Input (100% Load)	Max. Hourly	10 ⁶ Btu/hr (HHV)	7,333	7,432	7,475	7,383	7,320	7,475
H ₂ SO ₄	3-Hr	lb / 10 ⁶ Btu	0.0040	0.0040	0.0040	0.0040	0.0040	0.0040
		lb / MWh	0.036	0.036	0.037	0.036	0.036	0.037
		tpy	128.474	130.209	130.962	129.350	128.246	130.962
		lb/hr	29.3	29.7	29.9	29.5	29.3	29.90
		g/s	3.7	3.7	3.8	3.7	3.7	3.8
HCl	3-Hr	lb / 10 ⁶ Btu	0.0046	0.0019	0.0036	0.0035	0.0045	0.0046
		lb / MWh	0.041	0.017	0.033	0.032	0.040	0.041
		tpy	147.745	61.849	117.866	113.181	144.277	147.745
		lb/hr	33.7	14.1	26.9	25.8	32.9	33.7
		g/s	4.3	1.8	3.4	3.3	4.2	4.3
HF	3-Hr	lb / 10 ⁶ Btu	0.00045	0.00047	0.00046	0.00045	0.00044	0.00047
		lb / MWh	0.0040	0.0043	0.0042	0.0041	0.0039	0.0043
		tpy	14.453	15.300	15.061	14.552	14.107	15.300
		lb/hr	3.30	3.49	3.44	3.32	3.22	3.5
		g/s	0.42	0.44	0.43	0.4	0.4	0.4
CO ₂		Wt % Carbon, dry	73.48	73.95	73.65	76.82	75.09	76.8
		CO ₂ EF (lb/ton coal)	5,334	5,369	5,347	5,577	5,452	5,577
		Fuel Feed, dry (lb/hr)	556,167	595,636	578,801	564,549	544,392	595,636
		lb / 10 ⁶ Btu	202	215	207	213	203	214
		lb / MWh, gross	1,812	1,954	1,891	1,923	1,813	1,954
		lb/hr	1,483,383	1,599,015	1,547,507	1,574,325	1,483,919	1,599,015
		tpy	6,497,217	7,003,684	6,778,079	6,895,545	6,499,564	7,003,684

CA - Central Appalachian
PRB - Power River Basin
LA - Latin America
Petcoke - Petroleum Coke

Sources: ECT, 2007.
S&L, 2007.

**Table A-5. Taylor Energy Center
Main Solid Fuel-Fired Boiler - Organic Hazardous Air Pollutant Emission Rates**

Pollutant	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Maximum Fuel Consumption	ton/hr	299	336	377	316	293	377
1,1,1-Trichloroethane	lb/ton fuel	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05
	lb/hr	5.98E-03	6.72E-03	7.54E-03	6.32E-03	5.86E-03	7.54E-03
	tpy	0.0262	0.0294	0.0330	0.0277	0.0257	0.0330
2,4-Dinitrotoluene	lb/ton fuel	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
	lb/hr	8.37E-05	9.41E-05	1.06E-04	8.85E-05	8.20E-05	1.06E-04
	tpy	0.0004	0.0004	0.0005	0.0004	0.0004	0.0005
2-Chloroacetophenone	lb/ton fuel	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06
	lb/hr	2.09E-03	2.35E-03	2.64E-03	2.21E-03	2.05E-03	2.64E-03
	tpy	0.0092	0.0103	0.0116	0.0097	0.0090	0.0116
Acetaldehyde	lb/ton fuel	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06
	lb/hr	2.09E-03	2.35E-03	2.64E-03	2.21E-03	2.05E-03	2.64E-03
	tpy	0.0092	0.0103	0.0116	0.0097	0.0090	0.0116
Acetophenone	lb/ton fuel	1.50E-05	1.50E-05	1.50E-05	1.50E-05	1.50E-05	1.50E-05
	lb/hr	4.49E-03	5.04E-03	5.66E-03	4.74E-03	4.40E-03	5.66E-03
	tpy	0.0196	0.0221	0.0248	0.0208	0.0193	0.0248
Acrolein	lb/ton fuel	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04
	lb/hr	8.67E-02	9.74E-02	1.09E-01	9.16E-02	8.50E-02	1.09E-01
	tpy	0.3798	0.4268	0.4789	0.4014	0.3722	0.4789
Benzene	lb/ton fuel	1.30E-03	1.30E-03	1.30E-03	1.30E-03	1.30E-03	1.30E-03
	lb/hr	3.89E-01	4.37E-01	4.90E-01	4.11E-01	3.81E-01	4.90E-01
	tpy	1.7025	1.9132	2.1466	1.7993	1.6683	2.1466
Benzyl Chloride	lb/ton fuel	7.00E-04	7.00E-04	7.00E-04	7.00E-04	7.00E-04	7.00E-04
	lb/hr	2.09E-01	2.35E-01	2.64E-01	2.21E-01	2.05E-01	2.64E-01
	tpy	0.9167	1.0302	1.1559	0.9689	0.8983	1.1559
Biphenyl	lb/ton fuel	1.70E-06	1.70E-06	1.70E-06	1.70E-06	1.70E-06	1.70E-06
	lb/hr	5.08E-04	5.71E-04	6.41E-04	5.37E-04	4.98E-04	6.41E-04
	tpy	0.0022	0.0025	0.0028	0.0024	0.0022	0.0028
Bis(2-ethylhexyl)phthalate (DEHP)	lb/ton fuel	7.30E-05	7.30E-05	7.30E-05	7.30E-05	7.30E-05	7.30E-05
	lb/hr	2.18E-02	2.45E-02	2.75E-02	2.31E-02	2.14E-02	2.75E-02
	tpy	0.0956	0.1074	0.1205	0.1010	0.0937	0.1205
1,1,1-Trichloroethane	lb/ton fuel	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05
	lb/hr	5.98E-03	6.72E-03	7.54E-03	6.32E-03	5.86E-03	7.54E-03
	tpy	0.0262	0.0294	0.0330	0.0277	0.0257	0.0330
2,4-Dinitrotoluene	lb/ton fuel	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07	2.80E-07
	lb/hr	8.37E-05	9.41E-05	1.06E-04	8.85E-05	8.20E-05	1.06E-04
	tpy	0.0004	0.0004	0.0005	0.0004	0.0004	0.0005
2-Chloroacetophenone	lb/ton fuel	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06
	lb/hr	2.09E-03	2.35E-03	2.64E-03	2.21E-03	2.05E-03	2.64E-03
	tpy	0.0092	0.0103	0.0116	0.0097	0.0090	0.0116
Acetaldehyde	lb/ton fuel	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06	7.00E-06
	lb/hr	2.09E-03	2.35E-03	2.64E-03	2.21E-03	2.05E-03	2.64E-03
	tpy	0.0092	0.0103	0.0116	0.0097	0.0090	0.0116

Note: Organic compound emission factors (lb per ton of fuel) taken from Tables 1.1-12, 1.1-13, and 1.1-14 of AP-42, EPA, September 1998.

Sources: ECT, 2007.
S&L, 2007.

Table A-5. Taylor Energy Center (continued, Page 2 of 4)
Main Solid Fuel-Fired Boiler - Organic Hazardous Air Pollutant Emission Rates

Pollutant	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Maximum Fuel Consumption	ton/hr	299	336	377	316	293	377
Acetophenone	lb/ton fuel	1.50E-05	1.50E-05	1.50E-05	1.50E-05	1.50E-05	1.50E-05
	lb/hr	4.49E-03	5.04E-03	5.66E-03	4.74E-03	4.40E-03	5.66E-03
	tpy	0.0196	0.0221	0.0248	0.0208	0.0193	0.0248
Acrolein	lb/ton fuel	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04
	lb/hr	8.67E-02	9.74E-02	1.09E-01	9.16E-02	8.50E-02	1.09E-01
	tpy	0.3798	0.4268	0.4789	0.4014	0.3722	0.4789
Benzene	lb/ton fuel	1.30E-03	1.30E-03	1.30E-03	1.30E-03	1.30E-03	1.30E-03
	lb/hr	3.89E-01	4.37E-01	4.90E-01	4.11E-01	3.81E-01	4.90E-01
	tpy	1.7025	1.9132	2.1466	1.7993	1.6683	2.1466
Benzyl Chloride	lb/ton fuel	7.00E-04	7.00E-04	7.00E-04	7.00E-04	7.00E-04	7.00E-04
	lb/hr	2.09E-01	2.35E-01	2.64E-01	2.21E-01	2.05E-01	2.64E-01
	tpy	0.9167	1.0302	1.1559	0.9689	0.8983	1.1559
Biphenyl	lb/ton fuel	1.70E-06	1.70E-06	1.70E-06	1.70E-06	1.70E-06	1.70E-06
	lb/hr	5.08E-04	5.71E-04	6.41E-04	5.37E-04	4.98E-04	6.41E-04
	tpy	0.0022	0.0025	0.0028	0.0024	0.0022	0.0028
Bis(2-ethylhexyl)phthalate (DEHP)	lb/ton fuel	7.30E-05	7.30E-05	7.30E-05	7.30E-05	7.30E-05	7.30E-05
	lb/hr	2.18E-02	2.45E-02	2.75E-02	2.31E-02	2.14E-02	2.75E-02
	tpy	0.0956	0.1074	0.1205	0.1010	0.0937	0.1205
Bromoform	lb/ton fuel	3.90E-05	3.90E-05	3.90E-05	3.90E-05	3.90E-05	3.90E-05
	lb/hr	1.17E-02	1.31E-02	1.47E-02	1.23E-02	1.14E-02	1.47E-02
	tpy	0.0511	0.0574	0.0644	0.0540	0.0501	0.0644
Carbon Disulfide	lb/ton fuel	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04	1.30E-04
	lb/hr	3.89E-02	4.37E-02	4.90E-02	4.11E-02	3.81E-02	4.90E-02
	tpy	0.1703	0.1913	0.2147	0.1799	0.1668	0.2147
Chlorobenzene	lb/ton fuel	2.20E-05	2.20E-05	2.20E-05	2.20E-05	2.20E-05	2.20E-05
	lb/hr	6.58E-03	7.39E-03	8.29E-03	6.95E-03	6.45E-03	8.29E-03
	tpy	0.0288	0.0324	0.0363	0.0304	0.0282	0.0363
Chloroform	lb/ton fuel	5.90E-05	5.90E-05	5.90E-05	5.90E-05	5.90E-05	5.90E-05
	lb/hr	1.76E-02	1.98E-02	2.22E-02	1.86E-02	1.73E-02	2.22E-02
	tpy	0.0773	0.0868	0.0974	0.0817	0.0757	0.0974
Cumene	lb/ton fuel	5.30E-06	5.30E-06	5.30E-06	5.30E-06	5.30E-06	5.30E-06
	lb/hr	1.58E-03	1.78E-03	2.00E-03	1.67E-03	1.55E-03	2.00E-03
	tpy	0.0069	0.0078	0.0088	0.0073	0.0068	0.0088
Cyanide	lb/ton fuel	2.50E-03	2.50E-03	2.50E-03	2.50E-03	2.50E-03	2.50E-03
	lb/hr	7.48E-01	8.40E-01	9.43E-01	7.90E-01	7.33E-01	9.43E-01
	tpy	3.2741	3.6792	4.1282	3.4602	3.2084	4.1282
Dibenzofurans (Total PCDD/PCDF)	lb/ton fuel	1.76E-09	1.76E-09	1.76E-09	1.76E-09	1.76E-09	1.76E-09
	lb/hr	5.26E-07	5.91E-07	6.64E-07	5.56E-07	5.16E-07	6.64E-07
	tpy	0.000002	0.000003	0.000003	0.000002	0.000002	0.0000
Dimethyl Sulfate	lb/ton fuel	4.80E-05	4.80E-05	4.80E-05	4.80E-05	4.80E-05	4.80E-05
	lb/hr	1.44E-02	1.61E-02	1.81E-02	1.52E-02	1.41E-02	1.81E-02
	tpy	0.0629	0.0706	0.0793	0.0664	0.0616	0.0793
Ethyl Chloride	lb/ton fuel	4.20E-05	4.20E-05	4.20E-05	4.20E-05	4.20E-05	4.20E-05
	lb/hr	1.26E-02	1.41E-02	1.58E-02	1.33E-02	1.23E-02	1.58E-02
	tpy	0.0550	0.0618	0.0694	0.0581	0.0539	0.0694

Note: Organic compound emission factors (lb per ton of fuel) taken from Tables 1.1-12, 1.1-13, and 1.1-14 of AP-42, EPA, September 1998.

Sources: ECT, 2007.
S&L, 2007.

Table A-5. Taylor Energy Center (continued, Page 3 of 4)
Main Solid Fuel-Fired Boiler - Organic Hazardous Air Pollutant Emission Rates

Pollutant	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Maximum Fuel Consumption	ton/hr	299	336	377	316	293	377
Ethylbenzene	lb/ton fuel	9.40E-05	9.40E-05	9.40E-05	9.40E-05	9.40E-05	9.40E-05
	lb/hr	2.81E-02	3.16E-02	3.54E-02	2.97E-02	2.75E-02	3.54E-02
	tpy	0.1231	0.1383	0.1552	0.1301	0.1206	0.1552
Ethylene Dibromide	lb/ton fuel	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06	1.20E-06
	lb/hr	3.59E-04	4.03E-04	4.52E-04	3.79E-04	3.52E-04	4.52E-04
	tpy	0.0016	0.0018	0.0020	0.0017	0.0015	0.0020
Ethylene Dichloride	lb/ton fuel	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05
	lb/hr	1.20E-02	1.34E-02	1.51E-02	1.26E-02	1.17E-02	1.51E-02
	tpy	0.0524	0.0589	0.0661	0.0554	0.0513	0.0661
Formaldehyde	lb/ton fuel	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04
	lb/hr	7.18E-02	8.06E-02	9.05E-02	7.58E-02	7.03E-02	9.05E-02
	tpy	0.3143	0.3532	0.3963	0.3322	0.3080	0.3963
Hexane	lb/ton fuel	6.70E-05	6.70E-05	6.70E-05	6.70E-05	6.70E-05	6.70E-05
	lb/hr	2.00E-02	2.25E-02	2.53E-02	2.12E-02	1.96E-02	2.53E-02
	tpy	0.0877	0.0986	0.1106	0.0927	0.0860	0.1106
Isophorone	lb/ton fuel	5.80E-04	5.80E-04	5.80E-04	5.80E-04	5.80E-04	5.80E-04
	lb/hr	1.73E-01	1.95E-01	2.19E-01	1.83E-01	1.70E-01	2.19E-01
	tpy	0.7596	0.8536	0.9577	0.8028	0.7443	0.9577
Methyl Bromide	lb/ton fuel	1.60E-04	1.60E-04	1.60E-04	1.60E-04	1.60E-04	1.60E-04
	lb/hr	4.78E-02	5.38E-02	6.03E-02	5.06E-02	4.69E-02	6.03E-02
	tpy	0.2095	0.2355	0.2642	0.2215	0.2053	0.2642
Methyl Chloride	lb/ton fuel	5.30E-04	5.30E-04	5.30E-04	5.30E-04	5.30E-04	5.30E-04
	lb/hr	1.58E-01	1.78E-01	2.00E-01	1.67E-01	1.55E-01	2.00E-01
	tpy	0.6941	0.7800	0.8752	0.7336	0.6802	0.8752
Methyl Ethyl Ketone	lb/ton fuel	3.90E-04	3.90E-04	3.90E-04	3.90E-04	3.90E-04	3.90E-04
	lb/hr	1.17E-01	1.31E-01	1.47E-01	1.23E-01	1.14E-01	1.47E-01
	tpy	0.5108	0.5740	0.6440	0.5398	0.5005	0.6440
Methyl Hydrazine	lb/ton fuel	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04	1.70E-04
	lb/hr	5.08E-02	5.71E-02	6.41E-02	5.37E-02	4.98E-02	6.41E-02
	tpy	0.2226	0.2502	0.2807	0.2353	0.2182	0.2807
Methyl Methacrylate	lb/ton fuel	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05	2.00E-05
	lb/hr	5.98E-03	6.72E-03	7.54E-03	6.32E-03	5.86E-03	7.54E-03
	tpy	0.0262	0.0294	0.0330	0.0277	0.0257	0.0330
Methyl tert butyl ether	lb/ton fuel	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05	3.50E-05
	lb/hr	1.05E-02	1.18E-02	1.32E-02	1.11E-02	1.03E-02	1.32E-02
	tpy	0.0458	0.0515	0.0578	0.0484	0.0449	0.0578
Methylene Chloride	lb/ton fuel	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04	2.90E-04
	lb/hr	8.67E-02	9.74E-02	1.09E-01	9.16E-02	8.50E-02	1.09E-01
	tpy	0.3798	0.4268	0.4789	0.4014	0.3722	0.4789

Note: Organic compound emission factors (lb per ton of fuel) taken from Tables 1.1-12, 1.1-13, and 1.1-14 of AP-42, EPA, September 1998.

Sources: ECT, 2007.
S&L, 2007.

Table A-5. Taylor Energy Center (continued, Page 4 of 4)

Main Solid Fuel-Fired Boiler - Organic Hazardous Air Pollutant Emission Rates

Pollutant	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Maximum Fuel Consumption	ton/hr	299	336	377	316	293	377
Naphthalene	lb/ton fuel	1.30E-05	1.30E-05	1.30E-05	1.30E-05	1.30E-05	1.30E-05
	lb/hr	3.89E-03	4.37E-03	4.90E-03	4.11E-03	3.81E-03	4.90E-03
	tpy	0.0170	0.0191	0.0215	0.0180	0.0167	0.0215
Phenol	lb/ton fuel	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05	1.60E-05
	lb/hr	4.78E-03	5.38E-03	6.03E-03	5.06E-03	4.69E-03	6.03E-03
	tpy	0.0210	0.0235	0.0264	0.0221	0.0205	0.0264
Polycyclic Aromatic Hydrocarbons	lb/ton fuel	1.91E-05	1.91E-05	1.91E-05	1.91E-05	1.91E-05	1.91E-05
	lb/hr	5.70E-03	6.40E-03	7.18E-03	6.02E-03	5.58E-03	7.18E-03
	tpy	0.0250	0.0280	0.0315	0.0264	0.0245	0.0315
Propionaldehyde	lb/ton fuel	3.80E-04	3.80E-04	3.80E-04	3.80E-04	3.80E-04	3.80E-04
	lb/hr	1.14E-01	1.28E-01	1.43E-01	1.20E-01	1.11E-01	1.43E-01
	tpy	0.4977	0.5592	0.6275	0.5260	0.4877	0.6275
Styrene	lb/ton fuel	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05	2.50E-05
	lb/hr	7.48E-03	8.40E-03	9.43E-03	7.90E-03	7.33E-03	9.43E-03
	tpy	0.0327	0.0368	0.0413	0.0346	0.0321	0.0413
Tetrachloroethylene	lb/ton fuel	4.30E-05	4.30E-05	4.30E-05	4.30E-05	4.30E-05	4.30E-05
	lb/hr	1.29E-02	1.44E-02	1.62E-02	1.36E-02	1.26E-02	1.62E-02
	tpy	0.0563	0.0633	0.0710	0.0595	0.0552	0.0710
Toluene	lb/ton fuel	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04	2.40E-04
	lb/hr	7.18E-02	8.06E-02	9.05E-02	7.58E-02	7.03E-02	9.05E-02
	tpy	0.3143	0.3532	0.3963	0.3322	0.3080	0.3963
Vinyl Acetate	lb/ton fuel	7.60E-06	7.60E-06	7.60E-06	7.60E-06	7.60E-06	7.60E-06
	lb/hr	2.27E-03	2.55E-03	2.87E-03	2.40E-03	2.23E-03	2.87E-03
	tpy	0.0100	0.0112	0.0125	0.0105	0.0098	0.0125
Xylenes	lb/ton fuel	3.70E-05	3.70E-05	3.70E-05	3.70E-05	3.70E-05	3.70E-05
	lb/hr	1.11E-02	1.24E-02	1.39E-02	1.17E-02	1.08E-02	1.39E-02
	tpy	0.0485	0.0545	0.0611	0.0512	0.0475	0.0611

Note: Organic compound emission factors (lb per ton of fuel) taken from Tables 1.1-12, 1.1-13, and 1.1-14 of AP-42, EPA, September 1998.

Sources: ECT, 2007.
S&L, 2007.

Table A-6. Taylor Energy Center
Main Solid Fuel-Fired Boiler - Metallic Hazardous Air Pollutant Emission Rates (Excluding Hg)

Pollutant	Units	Fuel Type					Maximums
		Case 1	Case 2	Case 3	Case 4	Case 5	
		CA	LA	PRB/Petcoke ^{1,2}	LA/Petcoke	CA/Petcoke ^{2,3}	
Maximum Heat Input	10 ⁶ Btu/hr	7,333	7,432	7,475	7,383	7,320	7,475
Fuel Ash Fraction (A)	% / 100	0.1404	0.0850	0.0441	0.0678	0.1222	0.1404
Controlled PM Emission Rate (PM)	10 ⁶ Btu	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130
Emission Factor	lb / 10 ¹² Btu	a x (C / A x PM) ^b ; Table 1.1-16, AP-42, EPA, September 1998.					
Antimony (Sb)	C (ppmw)	1.15	N/A	0.53	N/A	1.15	1.15
	a	0.92		0.92		0.92	
	b	0.63		0.63		0.63	
	lb / 10 ¹² Btu	0.225		0.285		0.225	
	lb/hr	0.0016		0.0021		0.0016	0.0021
	tpy	0.0072		0.0093		0.0072	0.0093
Arsenic (As)	C (ppmw)	21.93	N/A	5.28	N/A	21.93	21.93
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb / 10 ¹² Btu	5.640		4.505		5.640	
	lb/hr	0.0414		0.0337		0.0414	0.0414
	tpy	0.1811		0.1475		0.1811	0.1811
Beryllium (Be)	C (ppmw)	2.80	N/A	0.75	N/A	2.80	2.80
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb / 10 ¹² Btu	0.990		0.868		0.990	
	lb/hr	0.0073		0.0065		0.0073	0.0073
	tpy	0.0318		0.0284		0.0318	0.0318
Cadmium (Cd)	C (ppmw)	0.08	N/A	0.11	N/A	0.08	0.11
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb / 10 ¹² Btu	0.050		0.168		0.050	
	lb/hr	0.0004		0.0013		0.0004	0.0013
	tpy	0.0016		0.0055		0.0016	0.0055
Chromium (Cr)	C (ppmw)	14.18	N/A	6.17	N/A	14.18	14.18
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb / 10 ¹² Btu	3.902		5.138		3.902	
	lb/hr	0.0286		0.0384		0.0286	0.0384
	tpy	0.1253		0.1682		0.1253	0.1682
Cobalt (Co)	C (ppmw)	7.00	N/A	2.06	N/A	7.00	7.00
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb / 10 ¹² Btu	2.149		2.034		2.149	
	lb/hr	0.0158		0.0152		0.0158	0.0158
	tpy	0.0690		0.0666		0.0690	0.0690
Lead (Pb)	C (ppmw)	7.64	N/A	4.42	N/A	7.64	7.64
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb / 10 ¹² Btu	2.314		3.878		2.314	
	lb/hr	0.0170		0.0290		0.0170	0.0290
	tpy	0.0743		0.1270		0.0743	0.1270
Manganese (Mn)	C (ppmw)	20.19	N/A	49.85	N/A	20.19	49.85
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb / 10 ¹² Btu	5.261		30.034		5.261	
	lb/hr	0.0386		0.2245		0.0386	0.2245
	tpy	0.1690		0.9833		0.1690	0.9833

N/A - Not available.

C = average fuel concentration from USGS National Coal Resources Data System, US Coal Quality Database; <http://energy.er.usgs.gov/products/databases/coalqual/intro.htm>.

¹ Metal concentrations reflect 100% PRB except for Ni and V.

² Metal concentrations for Ni and V based on 70%/30% PRB/petcoke blend.

³ Metal concentrations reflect 100% CA except for Ni and V.

Sources: ECT, 2007.
S&L, 2007.

Table A-6. Taylor Energy Center (continued, Page 2 of 2)

Main Solid Fuel-Fired Boiler - Metallic Hazardous Air Pollutant Emission Rates (Excluding Hg)

Pollutant	Units	Fuel Type					Maximums
		Case 1	Case 2	Case 3	Case 4	Case 5	
		CA	LA	PRB/Petcoke ^{1,2}	LA/Petcoke	CA/Petcoke ^{2,3}	
Maximum Heat Input	10 ⁶ Btu/hr	7,333	7,432	7,475	7,383	7,320	7,475
Fuel Ash Fraction (A)	% / 100	0.1404	0.0850	0.0441	0.0678	0.1222	0.1404
Controlled PM Emission Rate (PM)	10 ⁶ Btu	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130
Maximum Fuel Consumption	ton/hr	299	336	377	316	293	377
Emission Factor	lb / 10 ¹² Btu	a x (C / A x PM) ³ ; Table 1.1-16, AP-42, EPA, September 1998.					
Nickel (Ni)	C (ppmw)	14.88	N/A	64.20	N/A	71.91	71.91
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb / 10 ¹² Btu	4.065		37.193		4.065	
	lb/hr	0.0298		0.2780		0.0298	0.2780
	tpy	0.1306		1.2177		0.1306	1.2177
Selenium (Se)	C (ppmw)	3.58	N/A	0.94	N/A	3.58	3.58
	Uncontrolled	2.14		0.71		2.10	
	Control Efficiency	90.00		90.00		90.00	
	lb/hr	0.2142		0.0706		0.2099	0.2142
	tpy	0.9383		0.3091		0.9195	0.9383
Vanadium (V)	C (ppmw)	19.21	N/A	163.02	N/A	165.37	165.37
	a	3.10		3.10		3.10	
	b	0.85		0.85		0.85	
	lb / 10 ¹² Btu	5.043		81.742		5.043	
	lb/hr	0.0370		0.6110		0.0370	0.6110
	tpy	0.1620		2.6763		0.1620	2.6763

N/A - Not available.

C = average fuel concentration from USGS National Coal Resources Data System, US Coal Quality Database; <http://energy.er.usgs.gov/products/databases/coalqual/intro.htm>.¹ Metal concentrations reflect 100% PRB except for Ni and V.² Metal concentrations for Ni and V based on 70%/30% PRB/petcoke blend.³ Metal concentrations reflect 100% CA except for Ni and V.

Sources: ECT, 2007.

S&L, 2007.

**Table A-7. Taylor Energy Center
Main Solid Fuel-Fired Boiler - Hg Emission Rates**

Parameter	Units	Fuel Type					Maximums
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke	
Annual Operating Hours	hrs/yr	8,760	8,760	8,760	8,760	8,760	8,760
Output (100% Load)	MW, gross	818.5	818.5	818.5	818.5	818.5	818.5
Heat Input (100% Load)	10 ⁶ Btu/hr (HHV)	7,333	7,432	7,475	7,383	7,320	7,475
Fuel Hg Content	ppmwd	0.079	0.074	0.052	0.062	0.065	0.079
Fuel Moisture Content	% Vol.	7.03	11.40	23.26	10.81	7.26	23.26
Fuel Feed Rate (wet)	lb/hr	598,222	672,275	754,237	632,973	587,009	754,237
Fuel Feed Rate (dry)	lb/hr	556,167	595,636	578,801	564,549	544,392	595,636
Uncontrolled Hg Emission Rates	lb / 10 ¹² Btu	6.0	5.9	4.0	4.7	4.8	6.02
	10 ⁻⁶ lb / MWh	54.0	53.9	36.9	42.6	43.1	53.97
	lb/yr	387.0	386.7	264.5	305.3	309.0	387.00
Hg Control Efficiency	%	90	85	78	81	90	90
Controlled Hg Emission Rates	lb / 10 ¹² Btu	0.60	0.89	0.89	0.90	0.48	0.90
	lb x 10 ⁻⁶ / MWh	5.4	8.1	8.1	8.1	4.3	8.1
	lb/yr	38.7	58.0	58.2	58.0	30.9	58.20

Sources: ECT, 2007.
S&L, 2007.

POTENTIAL EMISSION INVENTORY WORKSHEET

Taylor Energy Center

A-8

Aux Boiler

EMISSION SOURCE TYPE

DISTILLATE FUEL OIL-FIRED EXTERNAL COMBUSTION SOURCES - CRITERIA POLLUTANTS

FACILITY AND SOURCE DESCRIPTION

Emission Source Description: Oil Fired Auxiliary Steam Boiler

Emission Control Method(s)/ID No.(s): Low NO_x Burner

Emission Point Description: Aux. Boiler

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Emission Factor (lb/10⁶ Btu) x Rated Capacity (10⁶ Btu/hr)

Emission (ton/yr) = Emission Factor (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

INPUT DATA AND EMISSIONS CALCULATIONS

Fuel Oil Density:	7.10	lb/gal
Fuel Oil Sulfur Content:	0.0015	weight % S
Maximum Heat Input:	375.0	10 ⁶ Btu/hr (HHV)
No. 2 Oil Heat Content:	137,000	Btu/gal (HHV)
Fuel Consumption:	2.74	1,000 gal/hr
Maximum hours per year	876	hrs/yr
No. of Boilers:	1	

Criteria Pollutant	Emission Factor		Maximum Controlled Emission Rates	
	(lb/1,000 gal)	(lb/MMBtu)	(lb/hr)	(tpy)
NO _x	12.3	0.09	33.8	14.8
CO	11.0	0.08	30.0	13.1
VOC	0.74	0.0054	2.0	0.89
SO ₂	0.21	0.0016	0.58	0.26
PM/PM ₁₀	3.2	0.023	8.6	3.8
Pb	1.23E-03	9.00E-06	0.0034	0.0015

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	TEC, 2007.
Maximum Heat Input (106 Btu/hr, HHV)	S&L, 2007.
Emission Factors	S&L, 2007.

NOTES AND OBSERVATIONS

DATA CONTROL

Prepared by:

J. Shrock, ECT

Date:

April 2007

POTENTIAL EMISSION INVENTORY WORKSHEET				A-9	
Taylor Energy Center				Aux Boiler	
EMISSION SOURCE TYPE					
NATURAL GAS FIRED EXTERNAL COMBUSTION SOURCES - HAZARDOUS AIR POLLUTANTS					
FACILITY AND SOURCE DESCRIPTION					
Emission Source Description:		Oil Fired Auxiliary Steam Boiler			
Emission Control Method(s)/ID No.(s):		Low NO _x Burner			
Emission Point Description:		Aux. Boiler			
EMISSION ESTIMATION EQUATIONS					
Emission (lb/hr) = Emission Factor (lb/10 ⁶ Btu) x Rated Capacity (10 ⁶ Btu/hr)					
Emission (ton/yr) = Emission Rate (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)					
INPUT DATA AND EMISSIONS CALCULATIONS					
Maximum Operating Hours:	876	hrs/yr			
Maximum Heat Input:	375.0	10 ⁶ Btu/hr (HHV)			
No. 2 Oil Heat Content:	137,000	Btu/gal			
Fuel Consumption:	2.74	1,000 gal/hr			
No. of Boilers:	1				
Criteria Pollutant	Emission Factor		Maximum Controlled Emission Rates		
	(lb/1,000 gal)	(lb/10 ¹² Btu)	(lb/hr)	(tpy)	
Organics					
1,1,1-Trichloroethane	2.36E-04	1.72E+00	6.46E-04	2.83E-04	
Acenaphthene	2.11E-05	1.54E-01	5.78E-05	2.53E-05	
Acenaphthylene	2.53E-07	1.85E-03	6.93E-07	3.03E-07	
Anthracene	1.22E-06	8.91E-03	3.34E-06	1.46E-06	
Benz(a)anthracene	4.01E-06	2.93E-02	1.10E-05	4.81E-06	
Benzene	2.14E-04	1.56E+00	5.86E-04	2.57E-04	
Benzo(b,k)fluoranthene	1.48E-06	1.08E-02	4.05E-06	1.77E-06	
Benzo(g,h,i)perylene	2.26E-06	1.65E-02	6.19E-06	2.71E-06	
Chrysene	2.38E-06	1.74E-02	6.51E-06	2.85E-06	
Dibenzo(a,h) anthracene	1.67E-06	1.22E-02	4.57E-06	2.00E-06	
Ethylbenzene	6.36E-05	4.64E-01	1.74E-04	7.63E-05	
Fluoranthene	4.84E-06	3.53E-02	1.32E-05	5.80E-06	
Fluorene	4.47E-06	3.26E-02	1.22E-05	5.36E-06	
Formaldehyde	3.30E-02	2.41E+02	9.03E-02	3.96E-02	
Indo(1,2,3-cd)pyrene	2.14E-06	1.56E-02	5.86E-06	2.57E-06	
Naphthalene	1.13E-03	8.25E+00	3.09E-03	1.35E-03	
OCDD	3.10E-09	2.26E-05	8.49E-09	3.72E-09	
o-xylene	1.09E-04	7.96E-01	2.98E-04	1.31E-04	
Phenanthrene	1.05E-05	7.66E-02	2.87E-05	1.26E-05	
Pyrene	4.25E-06	3.10E-02	1.16E-05	5.10E-06	
Toluene	6.20E-03	4.53E+01	1.70E-02	7.43E-03	
Metals					
Arsenic	5.48E-04	4.00E+00	1.50E-03	6.57E-04	
Beryllium	4.11E-04	3.00E+00	1.13E-03	4.93E-04	
Cadmium	4.11E-04	3.00E+00	1.13E-03	4.93E-04	
Chromium	4.11E-04	3.00E+00	1.13E-03	4.93E-04	
Copper	8.22E-04	6.00E+00	2.25E-03	9.86E-04	
Lead	1.23E-03	9.00E+00	3.38E-03	1.48E-03	
Manganese	8.22E-04	6.00E+00	2.25E-03	9.86E-04	
Mercury	4.11E-04	3.00E+00	1.13E-03	4.93E-04	
Nickel	4.11E-04	3.00E+00	1.13E-03	4.93E-04	
Selenium	2.06E-03	1.50E+01	5.63E-03	2.46E-03	
Zinc	5.48E-04	4.00E+00	1.50E-03	6.57E-04	
		Total	1.34E-01	5.89E-02	
Parameter					
Boiler Data		Data Source			
Emission Factors (Organic Pollutants)		S&L, 2007.			
Emission Factors (Metallic Pollutants)		AP-42, Table 1.3-9, September 1998.			
		AP-42, Table 1.3-10, September 1998.			
NOTES AND OBSERVATIONS					
DATA CONTROL					
Prepared by:		J. Shrock, ECT.		Date: April 2007	

POTENTIAL EMISSION INVENTORY WORKSHEET

A-10

Taylor Energy Center

Emerg. Gen

EMISSION SOURCE TYPE

EMERGENCY GENERATOR DIESEL ENGINE - CRITERIA POLLUTANTS

FACILITY AND SOURCE DESCRIPTION

Emission Source Description: Diesel Engine

Emission Control Method(s)/ID No.(s): Lean Burn

Emission Point Description:

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Emission Factor (g/kW-hr) x Engine Output (kW) x (0.0022046 lb/g)

Emission (ton/yr) = Emission Factor (g/kW-hr) x Engine Output (kW) x (0.0022046 lb/g) x Operating Period (hrs/yr) x (1 ton/ 2,000

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours:	96	hrs/yr
Diesel Fuel Oil Sulfur Content:	0.0015	weight % S
Diesel Fuel Oil Heat Content:	137,000	Btu/gal
Heat Input:	18.25	10 ⁶ Btu/hr (HHV)
Engine Output	1,640	kilowatts
Engine Output:	2,309	hp

Criteria Pollutant	Emission Factor (g/kW-hr)	Maximum Controlled Emission Rates	
		(lb/hr)	(tpy)
NO _x	6.0	21.7	1.04
CO	3.5	12.7	0.61
VOC	0.4	1.4	0.069
SO ₂	0.0079	0.029	0.0014
PM	0.2	0.72	0.035
PM ₁₀	0.2	0.72	0.035

SOURCES OF INPUT DATA

Parameter	Data Source
Engine Data	S&L, 2007.
Emission Factors	S&L, 2007., ECT, 2007.

NOTES AND OBSERVATIONS

The VOC factor is conservative because it includes non-VOCs (e.g., methane).

DATA CONTROL

Prepared by:

J. Shrock, ECT

Date:

April 2007

POTENTIAL EMISSION INVENTORY WORKSHEET			A-11
Taylor Energy Center			Emerg. Gen
EMISSION SOURCE TYPE			
EMERGENCY GENERATOR DIESEL ENGINE - TOXIC AIR POLLUTANTS			
FACILITY AND SOURCE DESCRIPTION			
Emission Source Description:	Diesel Engine		
Emission Control Method(s)/ID No.(s):	Lean Burn		
Emission Point Description:			
EMISSION ESTIMATION EQUATIONS			
Emission (lb/hr) = Emission Factor (lb/10 ⁶ Btu) x Engine Heat Input (10 ⁶ Btu/hr)			
Emission (ton/yr) = Emission Factor (lb/10 ⁶ Btu) x Engine Heat Input (10 ⁶ Btu/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)			
INPUT DATA AND EMISSIONS CALCULATIONS			
Operating Hours:	96	hrs/yr	
Diesel Oil Heat Content:	137,000	Btu/gal (HHV)	
Heat Input	18.25	10 ⁶ Btu/hr	
Engine Output	1,640	kilowatts	
Engine Output:	2,309	hp	
Hazardous Air Pollutant	Emission Factor (lb/10 ⁶ Btu)	Maximum Controlled Emission Rates	
		(lb/hr)	(tpy)
1,3-Butadiene	3.91E-05	7.14E-04	3.43E-05
Acetaldehyde	7.67E-04	1.40E-02	6.72E-04
Acrolein	9.25E-05	1.69E-03	8.10E-05
Benzene	9.33E-04	1.70E-02	8.17E-04
Formaldehyde	1.18E-03	2.15E-02	1.03E-03
Polycyclic Aromatic Hydrocarbons (PAH)	1.68E-04	3.07E-03	1.47E-04
Propylene	2.58E-03	4.71E-02	2.26E-03
Toluene	4.09E-04	7.46E-03	3.58E-04
Xylene	2.85E-04	5.20E-03	2.50E-04
		Total	5.65E-03
SOURCES OF INPUT DATA			
Parameter	Data Source		
Engine Data	S&L, 2006.		
Emission Factors	AP-42, Table 3.3-2, EPA, October 1996.		
NOTES AND OBSERVATIONS			
DATA CONTROL			
Prepared by:	J. Shrock, ECT	Date:	April 2007

POTENTIAL EMISSION INVENTORY WORKSHEET

A-12

Taylor Energy Center

Emerg. FWP

EMISSION SOURCE TYPE

FIREWATER PUMP DIESEL ENGINE - CRITERIA POLLUTANTS

FACILITY AND SOURCE DESCRIPTION

Emission Source Description: 432 hp Diesel Engine

Emission Control Method(s)/ID No.(s): Lean Burn

Emission Point Description: Exhaust stack

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Emission Factor (g/hp-hr) x Engine Output (hp) x (0.0022046 lb/g)

Emission (ton/yr) = Emission Factor (g/hp-hr) x Engine Output (hp) x (0.0022046 lb/g) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours:	96	hrs/yr
Diesel Fuel Oil Sulfur Content:	0.0015	weight % S
Diesel Fuel Oil Heat Content:	137,000	Btu/gal (HHV)
Heat Input:	3.33	10 ⁶ Btu/hr
Engine Output:	432	hp

Criteria Pollutant	Emission Factor (g/hp-hr)	Maximum Controlled Emission Rates	
		(lb/hr)	(tpy)
NO _x	2.0	1.9	0.091
CO	2.6	2.5	0.12
VOC	1.0	1.0	0.046
SO ₂	0.0054	0.005	0.00025
PM	0.15	0.14	0.0069
PM ₁₀	0.15	0.14	0.0069

SOURCES OF INPUT DATA

Parameter	Data Source
Engine Data	S&L, 2007.
Emission Factors	S&L, 2007., ECT, 2007.

NOTES AND OBSERVATIONS

The VOC factor is conservative because it includes non-VOCs (e.g., methane).

DATA CONTROL

Prepared by:

J. Shrock, ECT

Date:

April 2007

POTENTIAL EMISSION INVENTORY WORKSHEET

A-13

Taylor Energy Center

Emerg. FWP

EMISSION SOURCE TYPE

FIREWATER PUMP DIESEL ENGINE - TOXIC AIR POLLUTANTS

FACILITY AND SOURCE DESCRIPTION

Emission Source Description: 432 hp Diesel Engine

Emission Control Method(s)/ID No.(s): Lean Burn

Emission Point Description: Exhaust stack

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Emission Factor (lb/10⁶ Btu) x Engine Heat Input (10⁶ Btu/hr)

Emission (ton/yr) = Emission Factor (lb/10⁶ Btu) x Engine Heat Input (10⁶ Btu/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours: 96 hrs/yr

Diesel Fuel Oil Sulfur Content: 0.0015 weight % S

Diesel Fuel Oil Heat Content: 137,000 Btu/gal (HHV)

Heat Input: 3.33 10⁶ Btu/hr

Engine Output: 432 hp

Hazardous Air Pollutant	Emission Factor (lb/10 ⁶ Btu)	Maximum Controlled Emission Rates	
		(lb/hr)	(tpy)
1,3-Butadiene	3.91E-05	1.30E-04	6.25E-06
Acetaldehyde	7.67E-04	2.55E-03	1.23E-04
Acrolein	9.25E-05	3.08E-04	1.48E-05
Benzene	9.33E-04	3.11E-03	1.49E-04
Formaldehyde	1.18E-03	3.93E-03	1.89E-04
Polycyclic Aromatic Hydrocarbons (PAH)	1.68E-04	5.59E-04	2.69E-05
Propylene	2.58E-03	8.59E-03	4.12E-04
Toluene	4.09E-04	1.36E-03	6.54E-05
Xylene	2.85E-04	9.49E-04	4.56E-05
		Total	1.03E-03

SOURCES OF INPUT DATA

Parameter	Data Source
Engine Data	S&L, 2007.
Emission Factors	AP-42, Table 3.3-2, EPA, October 1996.

NOTES AND OBSERVATIONS

DATA CONTROL

Prepared by: J. Shrock, ECT

Date: April 2007

**Table A-14. Taylor Energy Center
Cooling Tower Particle Size Distribution**

Procedure Citation:

AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.

Calculating Realistic PM₁₀ Emissions from Cooling Towers

Cooling Tower Design Data:

Cooling Tower Recirculating Water Total Dissolved Solids:	20,000	ppmw
Cooling Tower PM ₁₀ Density (assumed NaCl):	2.2	g/cm ³

Particle Size Distribution:

Droplet Diameter (μm)	Droplet Volume (m ³)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m ³)	Particle Diameter (μm)	Mass Fraction (%)
10	5.24E-16	5.24E-10	1.05E-11	4.76E-18	2.087	0.000
20	4.19E-15	4.19E-09	8.38E-11	3.81E-17	4.174	0.196
30	1.41E-14	1.41E-08	2.83E-10	1.29E-16	6.261	0.226
40	3.35E-14	3.35E-08	6.70E-10	3.05E-16	8.348	0.514
50	6.54E-14	6.54E-08	1.31E-09	5.95E-16	10.435	1.816
60	1.13E-13	1.13E-07	2.26E-09	1.03E-15	12.522	5.702
70	1.80E-13	1.80E-07	3.59E-09	1.63E-15	14.609	21.348
90	3.82E-13	3.82E-07	7.63E-09	3.47E-15	18.784	49.812
110	6.97E-13	6.97E-07	1.39E-08	6.34E-15	22.958	70.509
130	1.15E-12	1.15E-06	2.30E-08	1.05E-14	27.132	82.023
150	1.77E-12	1.77E-06	3.53E-08	1.61E-14	31.306	88.012
180	3.05E-12	3.05E-06	6.11E-08	2.78E-14	37.567	91.032
210	4.85E-12	4.85E-06	9.70E-08	4.41E-14	43.828	92.468
240	7.24E-12	7.24E-06	1.45E-07	6.58E-14	50.090	94.091
270	1.03E-11	1.03E-05	2.06E-07	9.37E-14	56.351	94.689
300	1.41E-11	1.41E-05	2.83E-07	1.29E-13	62.612	96.288
350	2.24E-11	2.24E-05	4.49E-07	2.04E-13	73.047	97.011
400	3.35E-11	3.35E-05	6.70E-07	3.05E-13	83.483	98.340
450	4.77E-11	4.77E-05	9.54E-07	4.34E-13	93.918	99.071
500	6.54E-11	6.54E-05	1.31E-06	5.95E-13	104.353	99.071
600	1.13E-10	1.13E-04	2.26E-06	1.03E-12	125.224	100.000

Linear Interpolation:

Droplet Diameter (μm)	Droplet Volume (m ³)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m ³)	Particle Diameter (μm)	Mass Fraction (%)
40	3.35E-14	3.35E-08	6.70E-10	3.05E-16	8.348	0.514
50	6.54E-14	6.54E-08	1.31E-09	5.95E-16	10.435	1.816
					10.000	1.544

Mass Fraction of Cooling Tower PM ≤ PM ₁₀ :	0.015

Sources: ECT, 2007
S&L, 2007.

POTENTIAL EMISSION INVENTORY WORKSHEET

Taylor Energy Center

Table A-15
CTW

EMISSION SOURCE TYPE

COOLING TOWERS - PM/PM₁₀

FACILITY AND SOURCE DESCRIPTION

Emission Source Description: Mechanical Draft Cooling Tower
Emission Control Method(s)/ID No.(s): Mist Eliminators
Emission Point Description: Taylor Energy Center Cooling Tower

EMISSION ESTIMATION EQUATIONS

PM Emission (lb/hr) = Recirculating Water Flow Rate (gpm) x (Drift Loss Rate (%) / 100) x 8.345 lb/gal x (TDS (ppmw) / 10) x 60 min/hr

PM Emission (ton/yr) = PM Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

PM₁₀ Emission (lb/hr) = PM Emissions (lb/hr) x PM₁₀/PM Fraction

PM₁₀ Emission (ton/yr) = PM₁₀ Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

INPUT DATA AND EMISSIONS CALCULATIONS

Cooling Tower Data

Operating Hours:	8,760	hrs/yr		
Number of Cells:	20			
Recirculating Water Flow Rate:	334,920	gal/min		
Drift Loss Rate:	0.0005	%		
Total Dissolved Solids (TDS):	20,000	ppmw		
PM ₁₀ /PM Fraction:	0.015			
Number of Towers:	1			
Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (Total)	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
PM	0.84	3.67	16.77	73.45
PM ₁₀	0.013	0.06	0.26	1.13

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	S&L, 2007.
Recirculating Water Flow Rate (gpm)	S&L, 2007.
Drift Loss Rate (%)	S&L, 2007.
Total Dissolved Solids (ppmw)	S&L, 2007.
PM ₁₀ /PM Fraction:	ECT, 2007.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by: S&L April 2007
Data Entered by: T.Davis, ECT April 2007
Reviewed by: T.Davis, ECT April 2007

Table A-16. Taylor Energy Center
Solid Fuel Delivery, Handling, and Storage PM Emission Rates

ID	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM ₁₀ Emiss Factor	Emission Factor Units	Emission Control(s)	Control Efficiency		Pot PM	Fan Capacity (acfm)	Controlled PM Emissions	
											Emiss (lb/hr)		(lb/hr)	(tpy)
Rail Dump Station Enclosure														
TP-1	Railcar to south hopper	EP31, 32, 33	1,500	1,651,892	1,101	2.15E-04	lb/ton	WS	85	%	0.048			
TP-2	Railcar to north hopper	EP31, 32, 33	1,500	1,651,892	1,101	2.15E-04	lb/ton	WS	85	%	0.048			
EP-31	Vent fan at car unloading bldg										0.0323	2,500	0.032	0.036
EP-32	Vent fan at car unloading bldg										0.0323	2,500	0.032	0.036
EP-33	Vent fan at car unloading bldg										0.0323	2,500	0.032	0.036
Bottom Dump Track Hopper														
TP-3	Hopper to BF-1A to C-1	34	750	825,946	1,101	2.15E-04	lb/ton	Residual	75	%	0.040			
TP-4	Hopper to BF-1B to C-1	34	750	825,946	1,101	2.15E-04	lb/ton	Residual	75	%	0.040			
TP-5	Hopper to BF-1C to C-1	34	750	825,946	1,101	2.15E-04	lb/ton	Residual	75	%	0.040			
TP-6	Hopper to BF-1D to C-1	34	750	825,946	1,101	2.15E-04	lb/ton	Residual	75	%	0.040			
TP-7	C-1 to C-2	34	3,000	3,303,784	1,101	2.15E-04	lb/ton	Residual	75	%	0.161			
EP-34	Vent fan at C-2 tunnel exit										0.323	7,500	0.323	0.178
Transfer Tower														
TP-8	C-2 to C-3	35	3,000	3,303,784	1,101	2.15E-04	lb/ton	WS	85	%	0.097			
TP-10	C-2 to C-4 (coal Pile)	35	3,000	3,303,784	1,101	2.15E-04	lb/ton	Residual	75	%	0.161			
TP-11	C-2 to C-5 (pet coke pile)	35	3,000	3,303,784	1,101	2.15E-04	lb/ton	Residual	75	%	0.161			
TP-30	Coal from C-12 to C-3	35	900	3,303,784	3,671	2.15E-04	lb/ton	Residual	75	%	0.048			
EP-35	Vent fan at transfer tower										0.468	7,500	0.468	0.258
TP-9	C-3 to PRB & Pet Coke Active Piles	exposed	3,000	3,303,784	1,101	6.00E-04	lb/ton	WS	85	%	0.270		0.270	0.149
TP-12	C-4 to PRB Stockout Pile	exposed	3,000	2,643,027	881	6.00E-04	lb/ton	TC	75	%	0.450		0.450	0.198
TP-13	C-5 to Pet Coke Pile	exposed	3,000	660,757	220	6.00E-04	lb/ton	TC	75	%	0.450		0.450	0.050
TP-14	Active Pet Coke Pile to C-6A via Portal Reclaim B	exposed	1,800	660,757	367	6.00E-04	lb/ton	WS	85	%	0.162		0.162	0.030
TP-15	Active Coal Pile to C-6A via Portal Reclaim A	exposed	1,800	2,643,027	1,468	6.00E-04	lb/ton	WS	85	%	0.162		0.162	0.119
Coal Reclaim Hopper														
TP-16	PRB hoppers to BF-2A, 2B to C-7	EP-36	900	2,643,027	2,937	2.15E-04	lb/ton	Fogging	75	%	0.048			
EP-36	Vent fan at C-7 tunnel exit										0.048	3,000	0.048	0.071
Pet Coke Reclaim Hopper														
TP-17	Pet Coke hoppers to BF-3A, 3B to C-8	EP-38	900	660,757	734	2.15E-04	lb/ton	Fogging	75	%	0.048			
EP-38	Vent fan at C-8 tunnel exit										0.048	3,000	0.048	0.018
Transfer House														
TP-18	Coal from C-6A, C-7, or C-8 to C-9A	37	900	1,651,892	1,835	2.15E-04	lb/ton	Fogging	75	%	0.048			
TP-19	Coal from C-6A, C-7, or C-8 to C-9B	37	900	1,651,892	1,835	2.15E-04	lb/ton	Fogging	75	%	0.048			
TP-28	Coal from C-7 to C-12	37	900	1,651,892	1,835	2.15E-04	lb/ton	Fogging	75	%	0.048			
TP-29	Coal from C-8 to C-12	37	900	1,651,892	1,835	2.15E-04	lb/ton	Fogging	75	%	0.048			
EP-37	Vent fan at top of transfer house										0.194	6,000	0.194	0.356

Table A-16. Taylor Energy Center (Continued, Page 2 of 2)
Solid Fuel Delivery, Handling, and Storage PM Emission Rates

ID	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM ₁₀ Emiss Factor	Emission Factor Units	Emission Control(s)	Control Efficiency	Pot PM Emiss (lb/hr)	Fan Capacity (acfm)	Controlled PM Emissions	
												(lb/hr)	(tpy)
Crusher House													
TP-20	Coal C-9A to Crusher Surge Bin	EP-39 & 40	900	1,651,892	1,835	2.15E-04	lb/ton	none	0	0.194			
TP-21	Coal C-9B to Crusher Surge Bin	EP-39 & 40	900	1,651,892	1,835	2.15E-04	lb/ton	none	0	0.194			
EP-39	Ventilation Fan at Crusher House									0.194	7,500	0.194	0.178
EP-40	Ventilation Fan at Crusher House									0.194	7,500	0.194	0.178
C-1	Coal Crusher 1	EP-41	900	1,651,892	1,835	6.00E-03	lb/ton	none	0	5.400			
C-2	Coal Crusher 2	EP-41	900	1,651,892	1,835	6.00E-03	lb/ton	none	0	5.400			
TP-22	Coal Crusher Surge Bin to C-10A via BF-4A & Coal Crusher 1	EP-41	900	1,651,892	1,835	2.15E-04	lb/ton	none	0	0.194			
TP-23	Coal Crusher Surge Bin to C-10B via BF-4B & Coal Crusher 2	EP-41	900	1,651,892	1,835	2.15E-04	lb/ton	none	0	0.194			
EP-41	Dust Collection for C1, 2 & TP22,23							Baghouse	0.005	gr/dscf	22,000	0.943	1.731
Tripper Room													
TP-24	Coal C-10A to Tripper C-11A	EP-42	900	1,651,892	1,835	2.15E-04	lb/ton	none		0.194			
TP-25	Coal C-10B to Tripper C-11B	EP-42	900	1,651,892	1,835	2.15E-04	lb/ton	none		0.194			
TP-26	Coal from C-11A to Coal Silos	EP-42	900	1,651,892	1,835	2.15E-04	lb/ton	none		0.194			
TP-27	Coal from C-11B to Coal Silos	EP-42	900	1,651,892	1,835	2.15E-04	lb/ton	none		0.194			
EP-42	Dust Collection for TP-24, 25, 26, 27							Baghouse	0.005	gr/dscf	25,000	1.071	1.967
											Totals	5.07	5.58

WS = wet dust suppression system

Residual = residual wet suppression

TC = telescoping chute

Fogging = fog type dust suppression system

Total coal/pet coke: 3,303,784 ton/yr

Emissions from transfer points are based on the following equation contained in AP-42 Section 13.2.4.1, Aggregate Handling and Storage Piles (1/95)

$$\text{Emission Factor (EF) (lb/ton)} = k \times (0.0032) \times (U/5)^{1.3} / (M/2)^{1.4}$$

where: k = dimensionless constant = 0.74 for PM₁₀, and 0.35 for PM_{2.5}

U = mean wind speed (mph) = 6.6 mph as measured at Tallahassee Regional Airport.

For enclosed transfer points, an air flow of 3 mph is assumed.

M = material moisture content (%) = 6.9% for coal.

$$\text{EF(PM)} = 0.074 \times (0.0032) \times (3/5)^{1.3} / (6.9/2)^{1.4} = 2.15\text{E-}04 \text{ lb/ton (enclosed transfer point)}$$

$$\text{EF(PM)} = 0.074 \times (0.0032) \times (6.6/5)^{1.3} / (6.9/2)^{1.4} = 6.00\text{E-}04 \text{ lb/ton (exposed transfer point)}$$

Table A-17. Taylor Energy Center
Solid Fuel Delivery, Handling, and Storage PM₁₀ Emission Rates

ID	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM ₁₀ Emission Factor	Emission Factor Units	Emission Control(s)	Control Efficiency	Pot PM ₁₀ Emiss (lb/hr)	Fan Capacity (acfm)	Controlled PM ₁₀ Emissions		
												(lb/hr)	(tpy)	
Rail Dump Station Enclosure														
TP-1	Railcar to south hopper	EP31, 32, 33	1,500	1,651,892	1,101	1.02E-04	lb/ton	WS	85	%	0.023			
TP-2	Railcar to north hopper	EP31, 32, 33	1,500	1,651,892	1,101	1.02E-04	lb/ton	WS	85	%	0.023			
EP-31	Vent fan at car unloading bldg										0.0153	2,500	0.015	0.017
EP-32	Vent fan at car unloading bldg										0.0153	2,500	0.015	0.017
EP-33	Vent fan at car unloading bldg										0.0153	2,500	0.015	0.017
Bottom Dump Track Hopper														
TP-3	Hopper to BF-1A to C-1	34	750	825,946	1,101	1.02E-04	lb/ton	Residual	75	%	0.019			
TP-4	Hopper to BF-1B to C-1	34	750	825,946	1,101	1.02E-04	lb/ton	Residual	75	%	0.019			
TP-5	Hopper to BF-1C to C-1	34	750	825,946	1,101	1.02E-04	lb/ton	Residual	75	%	0.019			
TP-6	Hopper to BF-1D to C-1	34	750	825,946	1,101	1.02E-04	lb/ton	Residual	75	%	0.019			
TP-7	C-1 to C-2	34	3,000	3,303,784	1,101	1.02E-04	lb/ton	Residual	75	%	0.076			
EP-34	Vent fan at C-2 tunnel exit										0.153	7,500	0.153	0.084
Transfer Tower														
TP-8	C-2 to C-3	35	3,000	3,303,784	1,101	1.02E-04	lb/ton	WS	85	%	0.046			
TP-10	C-2 to C-4 (coal Pile)	35	3,000	3,303,784	1,101	1.02E-04	lb/ton	Residual	75	%	0.076			
TP-11	C-2 to C-5 (pet coke pile)	35	3,000	3,303,784	1,101	1.02E-04	lb/ton	Residual	75	%	0.076			
TP-30	Coal from C-12 to C-3	35	900	3,303,784	3,671	1.02E-04	lb/ton	Residual	75	%	0.023			
EP-35	Vent fan at transfer tower										0.221	7,500	0.221	0.122
TP-9	C-3 to PRB & Pet Coke Active Piles	exposed	3,000	3,303,784	1,101	2.84E-04	lb/ton	WS	85	%	0.128		0.128	0.070
TP-12	C-4 to PRB Stockout Pile	exposed	3,000	2,643,027	881	2.84E-04	lb/ton	TC	75	%	0.213		0.213	0.094
TP-13	C-5 to Pet Coke Pile	exposed	3,000	660,757	220	2.84E-04	lb/ton	TC	75	%	0.213		0.213	0.023
TP-14	Active Pet Coke Pile to C-6A via Portal Reclaim B	exposed	1,800	660,757	367	2.84E-04	lb/ton	WS	85	%	0.077		0.077	0.014
TP-15	Active Coal Pile to C-6A via Portal Reclaim A	exposed	1,800	2,643,027	1,468	2.84E-04	lb/ton	WS	85	%	0.077		0.077	0.056
Coal Reclaim Hopper														
TP-16	PRB hoppers to BF-2A, 2B to C-7	EP-36	900	2,643,027	2,937	1.02E-04	lb/ton	Fogging	75	%	0.023			
EP-36	Vent fan at C-7 tunnel exit										0.023	3,000	0.023	0.034
Pet Coke Reclaim Hopper														
TP-17	Pet Coke hoppers to BF-3A, 3B to C-8	EP-38	900	660,757	734	1.02E-04	lb/ton	Fogging	75	%	0.023			
EP-38	Vent fan at C-8 tunnel exit										0.023	3,000	0.023	0.008
Transfer House														
TP-18	Coal from C-6A, C-7, or C-8 to C-9A	37	900	1,651,892	1,835	1.02E-04	lb/ton	Fogging	75	%	0.023			
TP-19	Coal from C-6A, C-7, or C-8 to C-9B	37	900	1,651,892	1,835	1.02E-04	lb/ton	Fogging	75	%	0.023			
TP-28	Coal from C-7 to C-12	37	900	1,651,892	1,835	1.02E-04	lb/ton	Fogging	75	%	0.023			
TP-29	Coal from C-8 to C-12	37	900	1,651,892	1,835	1.02E-04	lb/ton	Fogging	75	%	0.023			
EP-37	Vent fan at top of transfer house										0.092	6,000	0.092	0.168

Table A-17. Taylor Energy Center (Continued, Page 2 of 2)
Solid Fuel Delivery, Handling, and Storage PM₁₀ Emission Rates

ID	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM ₁₀ Emission Factor	Emission Factor Units	Emission Control(s)	Control Efficiency	Pot PM ₁₀ Emiss (lb/hr)	Fan Capacity (acfm)	Controlled PM ₁₀ Emissions	
												(lb/hr)	(tpy)
Crusher House													
TP-20	Coal C-9A to Crusher Surge Bin	EP-39 & 40	900	1,651,892	1,835	1.02E-04	lb/ton	none	0	0.092			
TP-21	Coal C-9B to Crusher Surge Bin	EP-39 & 40	900	1,651,892	1,835	1.02E-04	lb/ton	none	0	0.092			
EP-39	Ventilation Fan at Crusher House									0.092	7,500	0.092	0.084
EP-40	Ventilation Fan at Crusher House									0.092	7,500	0.092	0.084
C-1	Coal Crusher 1	EP-41	900	1,651,892	1,835	6.00E-03	lb/ton	none	0	5,400			
C-2	Coal Crusher 2	EP-41	900	1,651,892	1,835	6.00E-03	lb/ton	none	0	5,400			
TP-22	Coal Crusher Surge Bin to C-10A via BF-4A & Coal Crusher 1	EP-41	900	1,651,892	1,835	1.02E-04	lb/ton	none	0	0.092			
TP-23	Coal Crusher Surge Bin to C-10B via BF-4B & Coal Crusher 2	EP-41	900	1,651,892	1,835	1.02E-04	lb/ton	none	0	0.092			
EP-41	Dust Collection for C1, 2 & TP22,23							Baghouse	0.005	gr/dscf	22,000	0.943	1.731
Tripper Room													
TP-24	Coal C-10A to Tripper C-11A	EP-42	900	1,651,892	1,835	1.02E-04	lb/ton	none		0.092			
TP-25	Coal C-10B to Tripper C-11B	EP-42	900	1,651,892	1,835	1.02E-04	lb/ton	none		0.092			
TP-26	Coal from C-11A to Coal Silos	EP-42	900	1,651,892	1,835	1.02E-04	lb/ton	none		0.092			
TP-27	Coal from C-11B to Coal Silos	EP-42	900	1,651,892	1,835	1.02E-04	lb/ton	none		0.092			
EP-42	Dust Collection for TP-24, 25, 26, 27							Baghouse	0.005	gr/dscf	25,000	1.071	1.967
											Totals	3.46	4.59

WS = wet dust suppression system

Residual = residual wet suppression

TC = telescoping chute

Fogging = fog type dust suppression system

Total coal/pet coke: 3,303,784 ton/yr

Emissions from transfer points are based on the following equation contained in AP-42 Section 13.2.4.1, Aggregate Handling and Storage Piles (1/95)

Emission Factor (EF) (lb/ton) = $k \times (0.0032) \times (U/5)^{1.3} / (M/2)^{1.4}$

where: k = dimensionless constant = 0.74 for PM₁₀, and 0.35 for PM_{2.5}.

U = mean wind speed (mph) = 6.6 mph as measured at Tallahassee Regional Airport.

For enclosed transfer points, an air flow of 3 mph is assumed.

M = material moisture content (%) = 6.9% for coal.

EF(PM₁₀) = $0.035 \times (0.0032) \times (3/5)^{1.3} / (6.9/2)^{1.4} = 1.02E-04$ lb/ton (enclosed transfer point)

EF(PM₁₀) = $0.035 \times (0.0032) \times (6.6/5)^{1.3} / (6.9/2)^{1.4} = 2.84E-04$ lb/ton (exposed transfer point)

**Table A-18. Taylor Energy Center
Limestone Delivery, Handling, and Storage PM Emission Rates**

Transfer Point	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM Emission Factor	Emission Factor Units	Emission Control(s)	Control Efficiency or Guaranteed Rate	Pot PM Emiss (lb/hr)	Fan Capacity (acfm)	Controlled PM Emissions (lb/hr) (tpy)	
TP-60 EP-67	Truck Dump Station Enclosure Transfer from Truck to Hopper Vent fan at truck hopper enclosure	EP-67	400	183,960	460	5.30E-03	lb/ton	WS	75 %	0.530	2,500	0.530	0.122
TP-61 EP-68	Truck Hopper Hopper to LH-1 via LHBF-1 Vent fan at LH-1 tunnel exit	EP-68	400	183,960	460	5.30E-03	lb/ton	Fogging	75 %	0.530	7,500	0.530	0.122
TP-62 EP-62	LH-1 to Limestone Stockout Pile	exposed	400	183,960	460	1.48E-02	lb/ton	TC	75 %	1.477	na	1.477	0.340
TP-63 EP-69	Active Stockpile Reclaim Hoppers Reclaim Hoppers to LHBF-2 & 3 to LH-2 Vent fan at LH-2 tunnel exit	EP-69	400	183,960	460	5.30E-03	lb/ton	Fogging	75 %	0.530	7,500	0.530	0.122
TP-64 EP-70 EP-71 EP-72	Limestone Preparation Building Limestone from LH-2 to LH-3 Vent fans at reactor prep building each vent exhausts 1/3 of emissions from TP-64	EP-70, 71, 72	400	183,960	460	5.30E-03	lb/ton	Fogging	75 %	0.530	2,500 2,500 2,500	0.177 0.177 0.177	0.041 0.041 0.041
TP-65 EP-73	LH-2 to Day Silo 1 Dust collection at top of Silo 1	EP-73	400	91,980	230	5.30E-03	lb/ton	BVF	0.005 gr/dscf	2.120	2,000	0.300	0.034
TP-66 EP-74	LH-3 to Day Silo 2 Dust collection at top of Silo 2	EP-74	400	91,980	230	5.30E-03	lb/ton	BVF	0.005 gr/dscf	2.120	2,000	0.300	0.034
												3.897	0.862

Fogging = fog type dust suppression system

WS = wet dust suppression system

BVF = bin vent filter

TC = telescoping chute

Emissions from transfer points are based on the following equation contained in AP-42 Section 13.2.4.1, Aggregate Handling and Storage Piles (1/95)

$$\text{Emission Factor (EF) (lb/ton)} = k \times (0.0032) \times (U/5)^{1.3} / (M/2)^{1.4}$$

where: k = dimensionless constant = 0.74 for PM, and 0.35 for PM₁₀.

U = mean wind speed (mph) = 6.6 mph as measured at Tallahassee Regional Airport.

For enclosed transfer points, an air flow of 3 mph is assumed.

M = material moisture content (%) = 0.7% for dry limestone.

Total limestone: 183,960 ton/yr

$$\text{EF(PM)} = 0.074 \times (0.0032) \times (1/5)^{1.3} / (0.7/2)^{1.4} = 5.30\text{E-}03 \text{ lb/ton (enclosed transfer point)}$$

$$\text{EF(PM)} = 0.074 \times (0.0032) \times (6.6/5)^{1.3} / (0.7/2)^{1.4} = 1.48\text{E-}02 \text{ lb/ton (exposed transfer point)}$$

**Table A-19. Taylor Energy Center
Limestone Delivery, Handling, and Storage PM₁₀ Emission Rates**

Transfer Point	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM Emission Factor	Emission Factor Units	Emission Control(s)	Control Efficiency or Guaranteed Rate	Pot PM ₁₀ Emiss (lb/hr)	Fan Capacity (acfm)	Controlled PM ₁₀ Emissions (lb/hr)	(tpy)
TP-60 EP-67	Truck Dump Station Enclosure Transfer from Truck to Hopper Vent fan at truck hopper enclosure	EP-67	400	183,960	460	2.51E-03	lb/ton	WS	75 %	0.251	2,500	0.251	0.058
TP-61 EP-68	Truck Hopper Hopper to LH-1 via LHBf-1 Vent fan at LH-1 tunnel exit	EP-68	400	183,960	460	2.51E-03	lb/ton	Fogging	75 %	0.251	7,500	0.251	0.058
TP-62 EP-62	LH-1 to Limestone Stockout Pile	exposed	400	183,960	460	6.99E-03	lb/ton	TC	75 %	0.699	na	0.699	0.161
TP-63 EP-69	Active Stockpile Reclaim Hoppers Reclaim Hoppers to LHBf-2 & 3 to LH-2 Vent fan at LH-2 tunnel exit	EP-69	400	183,960	460	2.51E-03	lb/ton	Fogging	75 %	0.251	7,500	0.251	0.058
TP-64 EP-70 EP-71 EP-72	Limestone Preparation Building Limestone from LH-2 to LH-3 Vent fans at reactor prep building each vent exhausts 1/3 of emissions from TP-64	EP-70, 71, 72	400	183,960	460	2.51E-03	lb/ton	Fogging	75 %	0.251	2,500 2,500 2,500	0.084 0.084 0.084	0.019 0.019 0.019
TP-65 EP-73	LH-2 to Day Silo 1 Dust collection at top of Silo 1	EP-73	400	91,980	230	2.51E-03	lb/ton	BVF	0.005 gr/dscf	1.003	2,000	0.300	0.034
TP-66 EP-74	LH-3 to Day Silo 2 Dust collection at top of Silo 2	EP-74	400	91,980	230	2.51E-03	lb/ton	BVF	0.005 gr/dscf	1.003	2,000	0.300	0.034
												2.301	0.460

Fogging = fog type dust suppression system

WS = wet dust suppression system

BVF = bin vent filter

TC = telescoping chute

Emissions from transfer points are based on the following equation contained in AP-42 Section 13.2.4.1, Aggregate Handling and Storage Piles (1/95)

$$\text{Emission Factor (EF) (lb/ton)} = k \times (0.0032) \times (U/5)^{1.3} / (M/2)^{1.4}$$

where: k = dimensionless constant = 0.74 for PM₁₀ and 0.35 for PM_{2.5}

U = mean wind speed (mph) = 6.6 mph as measured at Tallahassee Regional Airport.

For enclosed transfer points, an air flow of 3 mph is assumed.

M = material moisture content (%) = 0.7% for dry limestone.

Total limestone: 183,960 ton/yr

$$\text{EF}(\text{PM}_{10}) = 0.035 \times (0.0032) \times (1/5)^{1.3} / (0.7/2)^{1.4} = 2.51\text{E-}03 \text{ lb/ton (enclosed transfer point)}$$

$$\text{EF}(\text{PM}_{10}) = 0.035 \times (0.0032) \times (6.6/5)^{1.3} / (0.7/2)^{1.4} = 6.99\text{E-}03 \text{ lb/ton (exposed transfer point)}$$

**Table A-20. Taylor Energy Center
Fly Ash Handling, Storage, and Loadout PM Emission Rates**

ID	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM Emission Factor	Emission Units	Emission Control(s)	Control Efficiency or Guaranteed Rate	Pot PM (lb/hr)	Fan Capacity (acfm)	Controlled PM Emissions (lb/hr)	(tpy)
TP-80 EP-92	From Baghouse to Filter Separator (FS) 1 Vacuum exhaust	EP-92	40	63,291	1,582	8.49E-03	lb/ton	FS	99 0.005	% gr/dscf	3.40E-03 3,500	0.150	0.119
TP-81 EP-93	From Baghouse to FS 2 Vacuum exhaust	EP-93	40	63,291	1,582	8.49E-03	lb/ton	FS	99 0.005	% gr/dscf	3.40E-03 3,500	0.150	0.119
TP-82 TP-83 EP-94	Transfer from FS-1 to Silo 1 Transfer from FS-2 to Silo 1 Vent bag filter fan at top of Silo 1	EP-94 EP-94	40 40	63,291 63,291	1,582 1,582	8.49E-03 8.49E-03	lb/ton lb/ton	VBF VBF	95 95 0.005	% % gr/dscf	1.70E-02 1.70E-02 7,000	0.300	0.475
TP-84 EP-95	Storage Silo 1 to Pin Mixer 1 to Truck	EP-95	40	63,291	1,582	1.35E-04	lb/ton	WC	0	%	5.41E-03	0.005	0.004
TP-85 EP-96	Storage Silo 1 to Pin Mixer 2 to Truck	EP-96	40	63,291	1,582	1.35E-04	lb/ton	WC	0	%	5.41E-03	0.005	0.004
TP-88 TP-89 EP-97	Transfer from FS-1 to Silo 2 Transfer from FS-2 to Silo 2 Vent bag filter fan at top of Silo 2	EP-97 EP-97	40 40	63,291 63,291	1,582 1,582	8.49E-03 8.49E-03	lb/ton lb/ton	BVF BVF	95 95 0.005	% % gr/dscf	1.70E-02 1.70E-02 7,000	0.300	0.475
TP-90 EP-98	Storage Silo 2 to Pin Mixer 1 to Truck	EP-98	40	63,291	1,582	1.35E-04	lb/ton	WC	0	%	5.41E-03	0.005	0.004
TP-91 EP-99	Storage Silo 2 to Pin Mixer 2 to Truck	EP-99	40	63,291	1,582	1.35E-04	lb/ton	WC	0	%	5.41E-03	0.005	0.004
Totals												0.922	1.20

BVF = bin vent filter

FS = filter separator

WC = water conditioning (20% water added to ash before discharging to truck)

VBF = vent bag filter

Total fly ash: 253,164 ton/yr

Emissions from transfer points are based on the following equation contained in AP-42 Section 13.2.4.1, Aggregate Handling and Storage Piles (1/95)

$$\text{Emission Factor (EF) (lb/ton)} = k \times (0.0032) \times (U/5)^{1.3} / (M/2)^{1.4}$$

where: k = dimensionless constant = 0.74 for PM, and 0.35 for PM₁₀.

U = mean wind speed (mph) = 6.6 mph as measured at Tallahassee Regional Airport.

For enclosed transfer points, an air flow of 3 mph is assumed.

M = material moisture content (%) = 0.5% for dry ash, and 20% for ash subject to water conditioning.

$$\text{EF(PM)} = 0.074 \times (0.0032) \times (3/5)^{1.3} / (0.5/2)^{1.4} =$$

8.49E-03 lb/ton (enclosed transfer point)

$$\text{EF(PM)} = 0.074 \times (0.0032) \times (6.6/5)^{1.3} / (20/2)^{1.4} =$$

1.352E-04 lb/ton (unenclosed transfer point and WC)

**Table A-21. Taylor Energy Center
Fly Ash Handling, Storage, and Loadout PM₁₀ Emission Rates**

ID	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM ₁₀ Emission Factor	Emission Factor Units	Emission Control(s)	Control Efficiency or Guaranteed Rate	Pot PM ₁₀ (lb/hr)	Fan Capacity (acfm)	Controlled PM ₁₀ Emissions (lb/hr)	Controlled PM ₁₀ Emissions (tpy)
TP-80 EP-92	From Baghouse to Filter Separator (FS) 1 Vacuum exhauster	EP-92	40	63,291	1,582	4.02E-03	lb/ton	FS	99 0.005	% gr/dscf	1.61E-03 3,500	0.150	0.119
TP-81 EP-93	From Baghouse to FS 2 Vacuum exhauster	EP-93	40	63,291	1,582	4.02E-03	lb/ton	FS	99 0.005	% gr/dscf	1.61E-03 3,500	0.150	0.119
TP-82 TP-83 EP-94	Transfer from FS-1 to Silo 1 Transfer from FS-2 to Silo 1 Vent bag filter fan at top of Silo 1	EP-94 EP-94	40 40	63,291 63,291	1,582 1,582	4.02E-03 4.02E-03	lb/ton lb/ton	VBF VBF	95 95 0.005	% % gr/dscf	8.03E-03 8.03E-03 7,000	0.300	0.475
TP-84 EP-95	Storage Silo 1 to Pin Mixer 1 to Truck	EP-95	40	63,291	1,582	6.40E-05	lb/ton	WC	0	%	2.56E-03	0.003	0.002
TP-85 EP-96	Storage Silo 1 to Pin Mixer 2 to Truck	EP-96	40	63,291	1,582	6.40E-05	lb/ton	WC	0	%	2.56E-03	0.003	0.002
TP-88 TP-89 EP-97	Transfer from FS-1 to Silo 2 Transfer from FS-2 to Silo 2 Vent bag filter fan at top of Silo 2	EP-97 EP-97	40 40	63,291 63,291	1,582 1,582	4.02E-03 4.02E-03	lb/ton lb/ton	BVF BVF	95 95 0.005	% % gr/dscf	8.03E-03 8.03E-03 7,000	0.300	0.475
TP-90 EP-98	Storage Silo 2 to Pin Mixer 1 to Truck	EP-98	40	63,291	1,582	6.40E-05	lb/ton	WC	0	%	2.56E-03	0.003	0.002
TP-91 EP-99	Storage Silo 2 to Pin Mixer 2 to Truck	EP-99	40	63,291	1,582	6.40E-05	lb/ton	WC	0	%	2.56E-03	0.003	0.002
Totals												0.910	1.19

BVF = bin vent filter

FS = filter separator

WC = water conditioning (20% water added to ash before discharging to truck)

VBF = vent bag filter

Emissions from transfer points are based on the following equation contained in AP-42 Section 13.2.4.1, Aggregate Handling and Storage Piles (1/95)

$$\text{Emission Factor (EF) (lb/ton)} = k \times (0.0032) \times (U/5)^{1.3} / (M/2)^{1.4}$$

where: k = dimensionless constant = 0.74 for PM, and 0.35 for PM₁₀.

U = mean wind speed (mph) = 6.6 mph as measured at Tallahassee Regional Airport.

For enclosed transfer points, an air flow of 3 mph is assumed.

M = material moisture content (%) = 0.5% for dry ash, and 20% for ash subject to water conditioning.

Total fly ash: 253,164 ton/yr

$$\text{EF}(\text{PM}_{10}) = 0.035 \times (0.0032) \times (3/5)^{1.3} / (0.5/2)^{1.4} = 4.015\text{E-}03 \text{ lb/ton (enclosed transfer point)}$$

$$\text{EF}(\text{PM}_{10}) = 0.035 \times (0.0032) \times (6.6/5)^{1.3} / (20/2)^{1.4} = 6.397\text{E-}05 \text{ lb/ton (unenclosed transfer point and WC)}$$

**Table A-22. Taylor Energy Center
Gypsum Handling, Storage, and Loadout PM Emission Rates**

Transfer Point	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM Emission Factor	Emission Factor Units	Emission Control(s)	Ctrl Eff (%)	Pot PM Emiss (lb/hr)	Fan Capacity (acfm)	Controlled PM Emissions (lb/hr)	(tpy)
Gypsum Dewatering Building													
TP-101	From Vacuum Belt Feeder A to GH-1A	EP-111	40	90,939	2,273	1.28E-04	lb/ton	WC	0	0.0051			
TP-102	From Vacuum Belt Feeder A to GH-1B	EP-111	40	90,939	2,273	1.28E-04	lb/ton	WC	0	0.0051			
TP-103	From Vacuum Belt Feeder B to GH-1A	EP-111	40	90,939	2,273	1.28E-04	lb/ton	WC	0	0.0051			
TP-104	From Vacuum Belt Feeder B to GH-1B	EP-111	40	90,939	2,273	1.28E-04	lb/ton	WC	0	0.0051			
EP-111	Vent fan at gypsum dewatering building										7,500	0.0205	0.0233
Transfer House													
TP-105	From GH-1A to GH-2A	EP-112	40	181,877	4,547	1.28E-04	lb/ton	WC	0	0.0051			
TP-108	From GH-1B to GH-2B	EP-112	80	181,877	2,273	1.28E-04	lb/ton	WC	0	0.0102			
EP-112	Vent fan at gypsum transfer house										2,500	0.0154	0.0349
Gypsum Storage Building													
TP-106	From GH-2A to GH-3	EP-113 - 116	80	363,754	4,547	1.28E-04	lb/ton	WC	0	0.0102			
TP-107	From GH-3 to Gypsum Storage Pile	EP-113 - 116	80	363,754	4,547	1.28E-04	lb/ton	WC	0	0.0102			
TP-109	From GH-2B to Gypsum Emergency Pile	EP-113 - 116	80	90,939	1,137	1.28E-04	lb/ton	WC	0	0.0102			
TP-110	Truck loadout with front end loader	EP-113 - 116	80	363,754	4,547	1.28E-04	lb/ton	WC	0	0.0102			
EP-113	Vent fans at gypsum storage building										7,500	0.0102	0.0233
EP-114	(each vent exhausts 1/4 of emissions										7,500	0.0102	0.0233
EP-115	from TP-106, 107, 109, 110)										7,500	0.0102	0.0058
EP-116											7,500	0.0102	0.0233
												0.077	0.134

WC = water conditioning

Emissions from transfer points are based on the following equation contained in AP-42 Section 13.2.4.1, Aggregate Handling and Storage Piles (1/95)

$$\text{Emission Factor (EF) (lb/ton)} = k \times (0.0032) \times (U/5)^{1.3} / (M/2)^{1.4}$$

where: k = dimensionless constant = 0.74 for PM₁₀, and 0.35 for PM_{2.5}.

U = mean wind speed (mph) = 6.6 mph as measured at Tallahassee Regional Airport.

For enclosed transfer points, an air flow of 3 mph is assumed.

M = material moisture content (%) = 10% for gypsum

Total gypsum: 363,754 ton/yr

$$\text{EF(PM)} = 0.074 \times (0.0032) \times (3/5)^{1.3} / (10/2)^{1.4} = 1.281\text{E-}04 \text{ lb/ton (enclosed transfer point)}$$

$$\text{EF(PM)} = 0.074 \times (0.0032) \times (6.6/5)^{1.3} / (10/2)^{1.4} = 3.569\text{E-}04 \text{ lb/ton (exposed transfer point)}$$

**Table A-23. Taylor Energy Center
Gypsum Handling, Storage, and Loadout PM₁₀ Emission Rates**

Transfer Point	Area/Source Description	Emission Point	Max Capacity (ton/hr)	Average Throughput (ton/yr)	Ann Oper Hours	PM ₁₀ Emission Factor	Emission Factor Units	Emission Control(s)	Cnt'l Eff (%)	Pot PM ₁₀ Emiss (lb/hr)	Fan Capacity (acfm)	Controlled PM ₁₀ Emissions (lb/hr)	(tpy)
Gypsum Dewatering Building													
TP-101	From Vacuum Belt Feeder A to GH-1A	EP-111	40	90,939	2,273	6.06E-05	lb/ton	WC	0	0.0024			
TP-102	From Vacuum Belt Feeder A to GH-1B	EP-111	40	90,939	2,273	6.06E-05	lb/ton	WC	0	0.0024			
TP-103	From Vacuum Belt Feeder B to GH-1A	EP-111	40	90,939	2,273	6.06E-05	lb/ton	WC	0	0.0024			
TP-104	From Vacuum Belt Feeder B to GH-1B	EP-111	40	90,939	2,273	6.06E-05	lb/ton	WC	0	0.0024			
EP-111	Vent fan at gypsum dewatering building										7,500	0.0097	0.0110
Transfer House													
TP-105	From GH-1A to GH-2A	EP-112	40	181,877	4,547	6.06E-05	lb/ton	WC	0	0.0024			
TP-108	From GH-1B to GH-2B	EP-112	80	181,877	2,273	6.06E-05	lb/ton	WC	0	0.0048			
EP-112	Vent fan at gypsum transfer house										2,500	0.0073	0.0165
Gypsum Storage Building													
TP-106	From GH-2A to GH-3	EP-113 - 116	80	363,754	4,547	6.06E-05	lb/ton	WC	0	0.0048			
TP-107	From GH-3 to Gypsum Storage Pile	EP-113 - 116	80	363,754	4,547	6.06E-05	lb/ton	WC	0	0.0048			
TP-109	From GH-2B to Gypsum Emergency Pile	EP-113 - 116	80	90,939	1,137	6.06E-05	lb/ton	WC	0	0.0048			
TP-110	Truck loadout with front end loader	EP-113 - 116	80	363,754	4,547	6.06E-05	lb/ton	WC	0	0.0048			
EP-113	Vent fans at gypsum storage building										7,500	0.0048	0.0110
EP-114	(each vent exhausts 1/4 of emissions										7,500	0.0048	0.0110
EP-115	from TP-106, 107, 109, 110)										7,500	0.0048	0.0028
EP-116											7,500	0.0048	0.0110
												0.036	0.063

WC = water conditioning

Emissions from transfer points are based on the following equation contained in AP-42 Section 13.2.4.1, Aggregate Handling and Storage Piles (1/95)

$$\text{Emission Factor (EF) (lb/ton)} = k \times (0.0032) \times (U/5)^{1.3} / (M/2)^{1.4}$$

where: k = dimensionless constant = 0.74 for PM₁₀, and 0.35 for PM₁₀.

U = mean wind speed (mph) = 6.6 mph as measured at Tallahassee Regional Airport.

For enclosed transfer points, an air flow of 3 mph is assumed.

M = material moisture content (%) = 10% for gypsum

Total gypsum: 363,754 ton/yr

$$\text{EF}(\text{PM}_{10}) = 0.035 \times (0.0032) \times (3/5)^{1.3} / (10/2)^{1.4} = 6.057\text{E-}05 \text{ lb/ton (enclosed transfer point)}$$

$$\text{EF}(\text{PM}_{10}) = 0.035 \times (0.0032) \times (6.6/5)^{1.3} / (10/2)^{1.4} = 1.688\text{E-}04 \text{ lb/ton (exposed transfer point)}$$

**Table A-24. Taylor Energy Center
Storage Pile Bulldozer Operations PM / PM₁₀ Emission Rates**

Emission Point	Area/Source Description	Max Rate (ton/hr)	Average Operation (hr/yr)	PM Emission Factor	PM ₁₀ Emission Factor	Emission Factor Units	Emission Control(s)	Cnt'l Eff (%)	Max Unctl'd PM (lb/hr)	Controlled PM Emissions (lb/hr)	Controlled PM Emissions (tpy)	Max Unctl'd PM ₁₀ (lb/hr)	Controlled PM ₁₀ Emissions (lb/hr)	Controlled PM ₁₀ Emissions (tpy)
F-47	Coal Handling Bulldozing from PRB Stockout Pile to Inactive PRB Storage Pile	500	1,000	2.26E-01	1.22E-01	lb/VMT	none	0	0.45	0.45	0.23	0.24	0.24	0.12
F-48	Bulldozing from PRB Stockout Pile or Inactive PRB Storage Pile to Reclaim Hopper to feed coal to C-7	700	1,500	2.26E-01	1.22E-01	lb/VMT	none	0	0.45	0.45	0.34	0.24	0.24	0.18
F-51	Bulldozing from Pet Coke Stockout Pile to Inactive Pet Coke Storage Pile	500	300	2.26E-01	1.22E-01	lb/VMT	none	0	0.45	0.45	0.07	0.24	0.24	0.04
F-52	Bulldozing from Pet Coke Stockout Pile or Inactive Pet Coke Storage Pile to Reclaim Hopper to feed C-8	200	1,500	2.26E-01	1.22E-01	lb/VMT	none	0	0.45	0.45	0.34	0.24	0.24	0.18
F-76	Limestone Handling Bulldozing from Active Limestone Stockout Pile to Inactive Limestone Storage Pile	250	150	2.26E-01	1.22E-01	lb/VMT	none	0	0.45	0.45	0.03	0.24	0.24	0.02
F-78	Bulldozing from Active Limestone Stockout Pile or Inactive Limestone Storage Pile to Reclaim Hopper to feed LH-2	400	300	2.26E-01	1.22E-01	lb/VMT	none	0	0.45	0.45	0.07	0.24	0.24	0.04
									Total	2.72	1.07		1.47	0.58

Note: Emission factors (EFs) for grading operations based on AP-42: Section 11.9 Western Surface Coal Mining dated October 1998.

$$PM = .04 * (S)^{2.5} = 0.226 \text{ lb/VMT}$$

$$PM_{10} = 0.60 * .051 * (S)^{2.0} = 0.122 \text{ lb/VMT}$$

S = vehicle speed = 2 mph
VMT = vehicle miles traveled

**Table A-25. Taylor Energy Center
Storage Pile Wind Erosion PM / PM₁₀ Emission Rates**

Emission Point	Source Description	Length (ft)	Width (ft)	Height (ft)	Area (ft ²)	Area (m ²)	Volume (m ³)	Disturbed (%)	Area Disturbed (m ²)	PM Emission Factor	PM ₁₀ Emission Factor	Emission Control(s)	Cntrl Eff (%)	Max Unctrl'd PM			Max Unctrl'd PM ₁₀		
										(gm/m ³)	(gm/m ³)			(lb/hr)	(lb/hr)	(tpy)	(lb/hr)	(lb/hr)	(tpy)
F-43	Active PRB Coal Pile	400	150	63	73,000	6,782	107,038	100	6,782	10.10	5.05	PE & WS	81.25	6.29	1.18	0.03	3.15	0.59	0.014
F-45	PRB Stockout Pile (conical)	200	na	84	41,000	3,809	7,473	100	3,809	10.10	5.05	Residual	75	3.53	0.88	0.02	1.77	0.44	0.011
F-46	Inactive PRB Storage Pile	1,050	525	45	591,250	54,927	702,435	25	13,732	10.10	5.05	WS	85	12.74	1.91	0.05	1.59	0.24	0.006
F-44	Active Pet Coke Storage Pile	165	150	63	26,000	2,415	44,153	100	2,415	10.10	5.05	PE	81.25	2.24	0.42	0.01	1.12	0.21	0.005
F-49	Pet Coke Stockout Pile (conical)	200	na	84	41,000	3,809	7,473	100	3,809	10.10	5.05	Residual	75	3.53	0.88	0.02	1.77	0.44	0.011
F-50	Inactive Pet Coke Storage Pile	825	400	30	348,600	32,385	280,337	25	8,096	10.10	5.05	WS	85	7.51	1.13	0.03	0.94	0.14	0.003
F-75	Limestone Stockout Pile (conical)	100	na	40	10,000	929	2,965	100	929	10.10	5.05	none	0	0.86	0.86	0.02	0.43	0.43	0.010
F-77	Inactive Limestone Stockout Pile	250	250	30	71,000	6,596	53,094	25	1,649	10.10	5.05	WS	85	1.53	0.23	0.01	0.19	0.03	0.001
														Total	7.50	0.18	2.52	0.06	

Total facility throughput of coal is: 2,774,000 ton/yr 7,600 ton/dy
 Total facility throughput of pet coke is: 551,880 1,512
 Total coal/pet coke: 3,325,880 9,112

Emissions for wind erosion based on AP-42 Section 13.2.5 Industrial Wind Erosion dated January, 1995.

PE = partial enclosure

WS = water spray

Table A-25. Taylor Energy Center (continued, Page 2 of 2)
Storage Pile Wind Erosion PM / PM₁₀ Emission Rates

Month	Fastest Mile (mph)	Fastest Mile (m/s)	u* (m/s)	(u*-u _t [*])	(u*-u _t [*]) ²	P _{PM} (g/m ²)	P _{PM10} (g/m ²)
Jan	46	20.56	1.09	-0.03	0.001	0.00	0.00
Feb	40	17.88	0.95	-0.17	0.030	0.00	0.00
Mar	48	21.46	1.14	0.02	0.0003	0.45	0.22
Apr	35	15.65	0.83	-0.29	0.085	0.00	0.00
May	40	17.88	0.95	-0.17	0.030	0.00	0.00
Jun	44	19.67	1.04	-0.08	0.006	0.00	0.00
Jul	39	17.43	0.92	-0.20	0.038	0.00	0.00
Aug	58	25.93	1.37	0.25	0.065	10.10	5.05
Sep	46	20.56	1.09	-0.03	0.001	0.00	0.00
Oct	32	14.31	0.76	-0.36	0.131	0.00	0.00
Nov	40	17.88	0.95	-0.17	0.030	0.00	0.00
Dec	37	16.54	0.88	-0.24	0.0592	0.00	0.00
Highest monthly emission factor						10.10	5.05

Emission Factor Calculation for Disturbed Surfaces

EF (g/m²/yr) = k x Sum(P_i), sum is from i to N

k = particle size multiplier (= 1.0 for 30 um, and 0.5 for < 10 um particles)

N = number of disturbances per year

P_i = erosion potential based on fastest mile between disturbances (g/m²)

P = 58 (u* - u_t^{*})² + 25 (u* - u_t^{*})

P = 0 for u* ≤ u_t^{*}

P = the erosion potential function

u* is the friction velocity (= 0.053 times the the fastest mile (m/s))

u_t^{*} = threshold friction velocity (m/s) = 1.12 m/s for uncrusted coal pile from AP-42 Table 13.2.5-2

The fastest mile is defined as the fastest observed 1-minute value at the Tallahassee

Regional Airport for the period 1951 through 1980.

mph =miles per hour

m/s = meters per second

g/m² = grams per square meter

g/mo = grams per month

ECT, 2006.

POTENTIAL EMISSION INVENTORY WORKSHEET						A-26	
Taylor Energy Center						Paved Roads	
EMISSION SOURCE TYPE							
PAVED ROADS - CRITERIA POLLUTANTS							
FACILITY AND SOURCE DESCRIPTION							
Emission Source Description:		Paved Roads					
Emission Control Method(s)/ID No.(s):		Sweeping as needed					
Emission Point Description:		Fugitive					
EMISSION ESTIMATION EQUATIONS							
$E = [k * [sL/2]^{0.65} * [W/3]^{1.5} - C] * \text{Precipitation Correction}$							
E = particulate emission factor (having units matching the units of k)							
k = particle size multiplier for particle size range and units of interest							
sL = road surface silt loading							
W = average weight (tons) of the vehicles traveling the road							
C = emission factor for 1980's exhaust, break wear, and tire wear							
Precipitation Correction = 1 - [P/4N]							
P = number of days with over 0.01 inches of precipitation							
N = the number of days in the averaging period							
Daily VMT = round trip distance * number of trucks/day							
INPUT DATA AND EMISSIONS CALCULATIONS							
k for PM ₃₀	0.082	lb/vehicle miles traveled (VMT) for PM ₃₀ , AP-42 Table 13.2.1-1					
k for PM ₁₀	0.016	lb/VMT for PM ₁₀ , AP-42 Table 13.2.1-1					
sL	0.4	g/m ² (from AP-42: Table 13.2.1-3, normal ubiquitous baseline)					
W	30	Average vehicle weight (20 ton empty, 40 tons loaded)					
C	0.00047	lb/VMT for PM ₃₀ and PM ₁₀ , AP-42 Table 13.2.1-2					
P	115	days (from Figure AP-42: Figure 13.2.2-1)					
N	365	days					
Material			Load (ton)	# trips/yr	Trip Length (mi)	VMT/yr	
Limestone	183,960	ton/yr	20	9,198	3.13	28,744	
Bottom Ash	74,460	ton/yr	20	3,723	2.46	9,166	
Fly Ash	253,164	ton/yr	20	12,658	3.13	39,557	
Gypsum	363,654	ton/yr	20	18,183	2.84	51,655	
ZLD Solids	10,950	ton/yr	20	548	2.56	1,400	
Total	886,188			44,309	14.11	130,522	
Criteria Pollutant	Emission Factor (lb/VMT)	Maximum Uncontrolled Rates		Control Efficiency	Maximum Controlled Rates		
		(lb/hr)	(tpy)	(%)	(lb/hr)	(tpy)	
PM	0.84	12.50	54.74	50	6.25	27.37	
PM ₁₀	0.16	2.43	10.66	50	1.22	5.33	
SOURCES OF INPUT DATA							
Parameter		Data Source					
VMT and operation assumptions		S&L, 2007.					
Emission Factors		AP-42, Table 13.2.1-1, EPA, Dec, 2003.					
NOTES AND OBSERVATIONS							
DATA CONTROL							
Prepared by:		J. Shrock, ECT			Date:		April 2007

Table A-27. Taylor Energy Center

Construction Excavation and Fill Operations PM / PM₁₀ Emission Rates

Total Cut/Fill Material

2,860,059 yd³

77,221,593 ft³

3,474,972 tons

Emissions from transfer points are based on the following equation contained in AP-42 Section 13.2.4.1, Aggregate Handling and Storage Piles (1/95).

$$\text{Emission Factor (EF) (lb/ton)} = k \times (0.0032) \times (U/5)^{1.3} / (M/2)^{1.4}$$

where: k = dimensionless constant = 0.74 for PM, and 0.35 for PM₁₀.

U = mean wind speed (mph) = 6.6 mph as measured at Tallahassee Regional Airport.

M = material moisture content (%) = for soil 8%.

$$\text{EF(PM)} = 1.352\text{E-}04 \text{ lb/ton}$$

$$\text{EF(PM}_{10}\text{)} = 6.397\text{E-}05 \text{ lb/ton}$$

$$\text{PM} = 0.94 \text{ tpy (conservatively assumed that the material is transferred 4 times)}$$

$$\text{PM}_{10} = 0.44 \text{ tpy (conservatively assumed that the material is transferred 4 times)}$$

Table A-28. Taylor Energy Center Construction Grading and Earth Moving Operation PM₁₀ Emission Rates

Emission factors (EFs) for grading operations based on AP-42: Section 11.9 Western Surface Coal Mining dated October 1998.

$$\begin{aligned}
 \text{PM}_{10} &= 0.60 * .051 * (\text{S})^{2.0} = & 0.12 & \text{ lb/VMT} \\
 \text{S} = \text{ vehicle speed} &= & 2.00 & \text{ mph} \\
 & & 2,600 & \text{ hr/yr} \\
 & & 10 & \text{ number of equipment} \\
 \text{VMT} = \text{ vehicle miles traveled} & & 52,000 & \text{ VMT/yr} \\
 \text{PM}_{10} &= & 6,364.80 & \text{ lb/yr} \\
 \text{PM}_{10} &= & 3.18 & \text{ tpy}
 \end{aligned}$$

**Table A-29. Taylor Energy Center
Construction Unpaved Roads PM₁₀ Emission Rates**

Emission Source Description: Unpaved Roads
Emission Control Method(s)/ID No.(s): Watering as needed
Emission Point Description: Fugitive

$$E = k * (s/12)^a * (W/3)^b$$

Equation 1a of AP-42 Section 13.2.2
E= particulate emission factor (having units matching the units of k)
k = particle size multiplier for particle size range and units of interest
s = road surface silt loading
W = average weight (tons) of the vehicles traveling the road

Daily VMT = round trip distance * number of trucks/day

k	1.5	PM ₁₀ , AP-42 Table 13.2.2-2
s	8.5	% (from AP-42: Table 13.2.2-1, mean for construction site)
W	30	Average vehicle weight (20 ton empty, 40 tons loaded)
a	0.90	PM ₁₀ , AP-42 Table 13.2.2-2
b	0.45	PM ₁₀ , AP-42 Table 13.2.2-2
EF	3.10	lb/VMT for PM ₁₀

Material		Load (ton)	# trips/yr	Trip Length (mi)	VMT/yr
Soil	3,474,972 ton/yr	20	173,749	0.50	86,874
Misc	173,749 ton/yr	20	8,687	1.00	8,687
Total		3,648,721	182,436		95,562

Criteria Pollutant	Emission Factor (lb/VMT)	Maximum Uncontrolled Rates (lb/hr) (tpy)		Control Efficiency (%)	Maximum Controlled Rates (lb/hr) (tpy)	
PM ₁₀	3.10	0.06	148.10	50	0.03	74.1

Miscellaneous estimated as 5% of soil transfer.

**Table A-30. Taylor Energy Center
Construction Wind Erosion PM₁₀ Emission Rates**

(Emissions based on AP-42 Section 13.2.5 Industrial Wind Erosion dated January, 1995)

Month	Fastest Mile (mph)	Fastest Mile (m/s)	u* (m/s)	(u*-u _t [*])	(u*-u _t [*]) ²	P _{PM} (g/m ²)	P _{PM10} (g/m ²)
Jan	46	20.56	1.09	0.07	0.005	2.03	1.02
Feb	40	17.88	0.95	-0.07	0.005	0.00	0.00
Mar	48	21.46	1.14	0.12	0.0138	3.73	1.86
Apr	35	15.65	0.83	-0.19	0.036	0.00	0.00
May	40	17.88	0.95	-0.07	0.005	0.00	0.00
Jun	44	19.67	1.04	0.02	0.001	0.59	0.30
Jul	39	17.43	0.92	-0.10	0.009	0.00	0.00
Aug	58	25.93	1.37	0.35	0.125	16.13	8.07
Sep	46	20.56	1.09	0.07	0.005	2.03	1.02
Oct	32	14.31	0.76	-0.26	0.069	0.00	0.00
Nov	40	17.88	0.95	-0.07	0.005	0.00	0.00
Dec	37	16.54	0.88	-0.14	0.0206	0.00	0.00
Highest monthly emission factor						16.13	8.07
Average monthly emission factor						2.04	1.02

Emission Factor Calculation for Disturbed Surfaces

EF (g/m²/yr) = k x Sum(P_i), sum is from i to N

k = particle size multiplier (= 1.0 for 30 um, and 0.5 for < 10 um particles)

N = number of disturbances per year

P_i = erosion potential based on fastest mile between disturbances (g/m²)

P = 58 (u* - u_t^{*})² + 25 (u* - u_t^{*})

P = 0 for u* LE u_t^{*}

P = the erosion potential function

u* is the friction velocity (= 0.053 times the fastest mile (m/s))

u_t^{*} = threshold friction velocity (m/s) = 1.12 m/s for uncrusted coal pile from AP-42 Table 13.2.5-2

The fastest mile is defined as the fastest observed 1-minute value at the Tallahassee

Regional Airport for the period 1951 through 1980.

mph =miles per hour

m/s = meters per second

g/m² = grams per square meter

g/mo = grams per month

Total Area Disturbed (m ²)	Daily Percent Disturbed (%)	Daily Area Disturbed (m ²)	PM ₁₀ Emission Factor (gm/m ²)	Emission Control(s)	Cnt'l Eff (%)	Max Unctl'd PM ₁₀ (lb/hr)	Controlled PM ₁₀ (lb/hr)	Controlled PM ₁₀ (tpy)
3,354,963	5	167,748	1.02	WS	50	15.72	7.86	0.47

The total area of the site that may be disturbed at some time during the construction phase is 829 acres.

**Table A-31. Taylor Energy Center
Construction Diesel Engine Emission Rates**

Heavy Equipment	30	total number
Operating Hours	2,600	hr/yr (10 hr/dy, 5 dy/wk, 52 wk/yr)
Fuel Use	5.0	gal/hr
Fuel Use	390,000	gal/yr
Engine Rating	500	hp
Diesel Fuel	7.0	lb/gal
Fuel Sulfur	0.0015	wt% S

	EF (gm/hp-hr)	(tpy)
PM ₁₀	0.15	6.4
NO _x	2.5	107.5
SO ₂	-	0.041
CO	0.84	36.2
VOC	0.17	7.2

**Table A-32. Taylor Energy Center
Main Solid Fuel-Fired Boiler - Stack Parameters**

Parameter	Units	Fuel Type				
		Case 1 CA	Case 2 LA	Case 3 PRB/Petcoke	Case 4 LA/Petcoke	Case 5 CA/Petcoke
Height	ft	550	550	550	550	550
Above Grade	m	167.6	167.6	167.6	167.6	167.6
Exit	ft	30.8	30.8	30.8	30.8	30.8
Diameter	m	9.39	9.39	9.39	9.39	9.39
Stack Area	ft ²	745.1	745.1	745.1	745.1	745.1
Flow Rate	acfm	2,305,150	2,461,486	2,355,639	2,413,491	2,301,126
Exit	ft/sec	51.6	55.1	52.7	54.0	51.5
Velocity	m/sec	15.7	16.8	16.1	16.5	15.7
Exit	°F	130.0	130.0	130.0	130.0	130.0
Temperature	K	327.6	327.6	327.6	327.6	327.6

Sources: ECT, 2007.
S&L, 2007.

**Table A-33. Taylor Energy Center
Auxiliary Boiler, Emergency Diesel Engines,
and Cooling Tower Stack Parameters**

Parameter	Units	Emission Source			
		Auxiliary Boiler	Generator Diesel Engine	Fire Water Pump Diesel Engine	Cooling Tower ¹
Height	ft	200	20	12	60
Above Grade	m	61.0	6.1	3.7	18.3
Exit	ft	7.0	1.3	0.5	32.5
Diameter	m	2.13	0.38	0.15	9.91
Stack Area	ft ²	38.5	1.2	0.20	829.6
Flow Rate	acfm	159,131	9,688	1,752	1,283,189
Exit	ft/sec	68.9	131.6	148.7	25.8
Velocity	m/sec	21.0	40.1	45.3	7.9
Exit	°F	595.0	855.0	845.0	100.8
Temperature	K	585.9	730.4	724.8	311.4

¹ Per cell.

Sources: ECT, 2007.
S&L, 2007.

**Table A-34. Taylor Energy Center
Material Handling Stack Parameters**

Point Sources

Source ID	Source Description	Stack Diameter (ft)	Stack Diameter (m)	Stack Height (feet)	Stack Height (m)	Flow Rate (acfm)	Exit Velocity (ft/s)	Exit Velocity (m/s)	Temperature (°F)	Temperature (°K)
Coal Handling										
EP-31, 32, 33	Vent Fan at Coal Car Unload Bldg	2.00	0.61	30	9.14	2,500	13.3	4.04	0	255
EP-34	Vent Fan at C-2 tunnel exit	3.50	1.07	12	3.66	7,500	13.0	3.96	0	255
EP-35	Vent fan at transfer tower	3.50	1.07	70	21.34	7,500	13.0	3.96	0	255
EP-36	Vent fan at C-7 tunnel exit	2.21	0.67	12	3.66	3,000	13.0	3.97	0	255
EP-37	Vent fan at transfer house	3.13	0.95	60	18.29	6,000	13.0	3.96	0	255
EP-38	Vent fan at C-8 tunnel exit	2.21	0.67	12	3.66	3,000	13.0	3.97	0	255
EP-39	Vent fan at crusher house	3.50	1.07	90	27.43	7,500	13.0	3.96	0	255
EP-40	Vent fan at crusher house	3.50	1.07	90	27.43	7,500	13.0	3.96	0	255
EP-41	Dust collection at crusher house	2.64	0.80	15	4.57	22,000	67.0	20.42	0	255
EP-42	Dust collection at boiler silo area	2.81	0.86	200	60.96	25,000	67.2	20.48	0	255
Limestone Handling										
EP-67	Vent fan at limestone truck hopper enclosure	2.00	0.61	30	9.14	2,500	13.3	4.04	0	255
EP-68	Vent fan at conveyor LH-1 tunnel exit	3.50	1.07	12	3.66	7,500	13.0	3.96	0	255
EP-69	Vent fan at conveyor LH-2 tunnel exit	3.50	1.07	12	3.66	7,500	13.0	3.96	0	255
EP-70	Vent fan at reactant preparation bldg	2.00	0.61	125	38.10	2,500	13.3	4.04	0	255
EP-71	Vent fan at reactant preparation bldg	2.00	0.61	125	38.10	2,500	13.3	4.04	0	255
EP-72	Vent fan at reactant preparation bldg	2.00	0.61	125	38.10	2,500	13.3	4.04	0	255
EP-73	Dust collection at top of LS day silo1	0.80	0.24	110	33.53	2,000	66.3	20.21	0	255
EP-74	Dust collection at top of LS day silo2	0.80	0.24	110	33.53	2,000	66.3	20.21	0	255
FGD Ash Handling										
EP-92	Vacuum exhausters located in blower house	1.07	0.33	14	4.27	3,500	64.9	19.77	0	255
EP-93	Vacuum exhausters located in blower house	1.07	0.33	14	4.27	3,500	64.9	19.77	0	255
EP-94	Vent bag filter at top of fly ash silo 1	0.92	0.28	126	38.40	3,000	75.2	22.93	0	255
EP-97	Vent bag filter at top of fly ash silo 2	0.92	0.28	126	38.40	3,000	75.2	22.93	0	255
Gypsum Handling										
EP-111	Vent fan at gypsum dewatering bldg	3.50	1.07	50	15.24	7,500	13.0	3.96	0	255
EP-112	Vent fan at transfer house	2.00	0.61	30	9.14	2,500	13.3	4.04	0	255
EP-113	Vent fan at gypsum storage bldg	3.50	1.07	50	15.24	7,500	13.0	3.96	0	255
EP-114	Vent fan at gypsum storage bldg	3.50	1.07	50	15.24	7,500	13.0	3.96	0	255
EP-115	Vent fan at gypsum storage bldg	3.50	1.07	50	15.24	7,500	13.0	3.96	0	255
EP-116	Vent fan at gypsum storage bldg	3.50	1.07	50	15.24	7,500	13.0	3.96	0	255

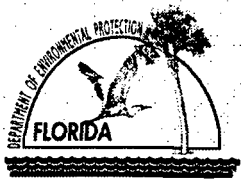
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MAY 24 2007

BUREAU OF AIR REGULATION

APPENDIX B

FDEP AIR PERMIT APPLICATION 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 any air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes 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/renewal Title V air operation permit.

Air Construction Permit & Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Florida Municipal Power Agency JEA		Reedy Creek Improvement District City of Tallahassee
2. Site Name: Taylor Energy Center		
3. Facility Identification Number: N/A		
4. Facility Location... Street Address or Other Locator: South of U.S. Highway 27, 5 Miles Southeast of Perry City: Southeast of Perry County: Taylor Zip Code: 32347		
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No	

Application Contact

1. Application Contact Name: Michael L. Kurtz, Executive Director		
2. Application Contact Mailing Address Organization/Firm: Taylor Energy Center Street Address: 3701 Northwest 98th Street City: Gainesville State: Florida Zip Code: 32606		
3. Application Contact Telephone Numbers... Telephone: (352) 248-3345 ext. Fax: (904) 665-0240		
4. Application Contact Email Address: MKurtz@colectric.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

PSD air construction permit application for a nominal 800-megawatt (MW) advanced supercritical pulverized coal-fired power plant that will burn a blend of petroleum coke (petcoke) and coal, with scheduled commercial operation commencing in May 2012. The Taylor Energy Center (TEC) site is located in east-central Taylor County five miles southeast of the city of Perry. A detailed description of the TEC project is provided in Section 2.0.

TEC is being licensed under the Florida Electrical Power Plant Siting Act (FEPPSA).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	Supercritical Main Boiler	AC1A	
002	Auxiliary Boiler	AC1A	
003	Mechanical Draft Cooling Tower	AC1A	
004	Emergency Generator Diesel Engine	AC1A	
005	Emergency Firewater Pump Diesel Engine	AC1A	
006	Solid Fuel, Limestone, and Byproduct Material Handling and Storage Systems	AC1A	

Application Processing Fee

Check one: ☒ Attached - Amount: \$ 7,500 ☐ Not Applicable

Application processing fee of \$7,500 is required pursuant to Rule 62-4.050(4)(a)1, F.A.C.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name:

Michael L. Kurtz, Executive Director

2. Owner/Authorized Representative Mailing Address

Organization/Firm: **Taylor Energy Center**

Street Address: **3701 Northwest 98th Street**

City: **Gainesville**

State: **Florida**

Zip Code: **32606**

3. Owner/Authorized Representative Telephone Numbers

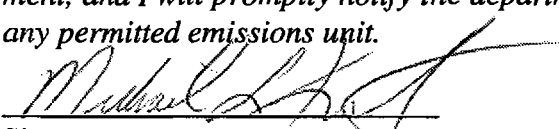
Telephone: **(352) 248-3345**

ext. Fax: **(904) 665-0240**

4. Owner/Authorized Representative Email Address: **MKurtz@coelectric.com**

5. Owner/Authorized Representative Statement:

I, the undersigned, am the owner or authorized representative of the facility 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 requirements identified in this application to which the facility 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.


Signature

4/30/07
Date

APPLICATION INFORMATION

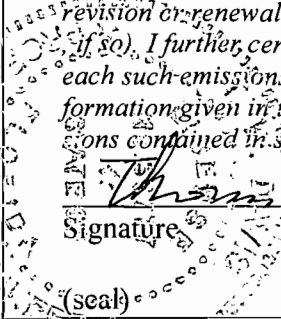
Application Responsible Official Certification **NOT APPLICABLE**

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V 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.			
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:			
6. Application Responsible Official Certification: <i>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.</i> _____ Signature _____ Date			

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Thomas W. Davis Registration Number: 36777
2. Professional Engineer Mailing Address Organization/Firm: Environmental Consulting & Technology, Inc. Street Address: 3701 Northwest 98th Street City: Gainesville State: FL Zip Code: 32606
3. Professional Engineer Telephone Numbers... Telephone: (352) 332-6230 ext. 11351 Fax: (352) 332-6722
4. Professional Engineer Email Address: tdavis@ectinc.com
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> (1) <i>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</i> (2) <i>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.</i> (3) <i>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.</i> (4) <i>If the purpose of this application is to obtain an air construction permit (check here ☒, 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.</i> (5) <i>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.</i>  Signature: <u><i>Thomas W. Davis</i></u> Date: <u>4/30/07</u> (seal)

Attach any exception to certification statement.

APPLICATION INFORMATION

Professional Engineer Certification1. Professional Engineer Name: **Thomas W. Davis**Registration Number: **36777**

2. Professional Engineer Mailing Address

Organization/Firm: **Environmental Consulting & Technology, Inc.**Street Address: **3701 Northwest 98th Street**City: **Gainesville**State: **FL**Zip Code: **32606**

3. Professional Engineer Telephone Numbers...

Telephone: **(352) 332-6230** ext. **11351** Fax: **(352) 332-6722**4. Professional Engineer Email Address: **tdavis@ectinc.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 ☒ 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

4/30/07

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 261.5 North (km) 3,330.2		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 30/04/54 Longitude (DD/MM/SS) 83/28/30	
3. Governmental Facility Code: 4	4. Facility Status Code: C	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment : Facility coordinate datum is North American Datum 1927 (NAD 27).			

Facility Contact

1. Facility Contact Name: Michael L. Kurtz, Executive Director
2. Facility Contact Mailing Address Organization/Firm: Taylor Energy Center Street Address: 3701 Northwest 98th Street City: Gainesville State: Florida Zip Code: 32606
3. Facility Contact Telephone Numbers: Telephone: (352) 248-3345 ext. Fax: (904) 665-0240
4. Facility Contact Email Address: MKurtz@colectric.com

Facility Primary Responsible Official **NOT APPLICABLE**

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 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 60)	
9.	☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR 60)	
10.	☒ One or More Emissions Units Subject to NESHAP (40 CFR 61 or Part 63)	
11.	☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12.	Facility Regulatory Classifications Comment: Applicable State and Federal emission standards are discussed in Section 4.0.	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NO_x	A	N
SO₂	A	N
PM	A	N
PM₁₀	A	N
CO	A	N
VOC	A	N
SAM	A	N
HCl (H106)	A	N
HF (H107)	A	N
Hg (H114)	B	N
HAPS	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps **NOT APPLICABLE**

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: <u>Section 2.0</u> ☐ 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: <u>Section 2.0</u> ☐ 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: <u>Section 5.0</u> ☐ Previously Submitted, Date: _____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: <u>Section 2.0</u> ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: <u>Section 2.0</u>
3. Rule Applicability Analysis: ☒ Attached, Document ID: <u>Section 4.0</u>
4. List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.): ☐ Attached, Document ID: _____ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: ☒ Attached, Document ID: <u>Section 2.0</u> ☐ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☒ Attached, Document ID: <u>Section 8.0</u> ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: <u>Sections 7.0 and 10.0</u> ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: <u>Section 9.0</u> ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: <u>Section 9.0</u> ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for FESOP Applications **NOT APPLICABLE**

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 **NOT APPLICABLE**

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

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [1] of [6]

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:

Advanced supercritical steam boiler fired with pulverized solid fuels including coal and coal/petcoke blends.

3. Emissions Unit Identification Number: **001 (Main Boiler)**

4. Emissions
Unit Status
Code:
C

5. Commence
Construction
Date:
N/A

6. Initial
Startup
Date:
N/A

7. Emissions Unit
Major Group
SIC Code:
49

8. Acid Rain Unit?
☒ Yes
☐ No

9. Package Unit:

Manufacturer:

Model Number:

10. Generator Nameplate Rating: **800 MW (nominal, gross)**

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [1] of [6]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

NO_x

Low NO_x Burners (LNB [Control Device Code 205]

Overfire Air (OFA) [Control Device Code 204]

Selective Catalytic Reduction (SCR) [Control Device Code 139]

CO and VOC

Low NO_x Burners (LNB [Control Device Code 205]

Overfire Air (OFA) [Control Device Code 204]

PM/PM₁₀

Fabric Filter (FF) – Medium Temperature (180 – 250 °F) [Control Device Code 017]

Wet Electrostatic Precipitator (WESP) [Control Device Code 146]

SO₂

Wet Flue Gas Desulfurization (WFGD) – Wet Lime Slurry Scrubbing
[Control Device Code 067]

Hg

Dry Sorbent Injection [Control Device Code 206]

Cobenefits – LNB, OFA, SCR, FF, WFGD, and WESP

H₂SO₄ Mist, HCl and HF

Wet Flue Gas Desulfurization (WFGD) – Wet Lime Slurry Scrubbing
[Control Device Code 067]

Wet Electrostatic Precipitator (WESP) [Control Device Code 146]

2. Control Device or Method Code(s): 205, 204, 139, 017, 146, 067, 206

Section [1] of [6]

(Optional for unregulated emissions units.)

1. Maximum Process or Throughput Rate: N/A
2. Maximum Production Rate: N/A
3. Maximum Heat Input Rate: 7,475 million Btu/hr, HHV
4. Maximum Incineration Rate: N/A 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:

EMISSIONS UNIT INFORMATION

Section [1] of [6]

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: 54		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V		6. Stack Height: 550 feet	
		7. Exit Diameter: 30.8 feet	
8. Exit Temperature: 130 °F		9. Actual Volumetric Flow Rate: 2,461,500 acfm	
		10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates Zone: 17 East (km): 261.45 North (km): 3,330.24		14. Emission Point Latitude/Longitude N/A Latitude (DD/MM/SS) N/A Longitude (DD/MM/SS)	
15. Emission Point Comment: Emission point coordinate datum is North American Datum 1927 (NAD 27).			

EMISSIONS UNIT INFORMATION

Section [1] of [6]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 3

1. Segment Description (Process/Fuel Type): Bituminous/subbituminous coal combusted in pulverized coal dry bottom boiler.		
2. Source Classification Code (SCC): 1-01-002-02		3. SCC Units: Tons Burned
4. Maximum Hourly Rate: 304.9	5. Maximum Annual Rate: 2,670,950	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: See Comment	8. Maximum % Ash: 11.3	9. Million Btu per SCC Unit: 24.5, HHV
10. Segment Comment: Fuel data shown above is based on design data for Central Appalachian coal and a boiler heat input of 7,475 MMBtu/hr. Data will vary depending on coal type. Maximum sulfur content will vary with coal heat content but will not exceed 3.46 lb SO₂/MMBtu.		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): Petroleum coke (petcoke) combusted in pulverized coal dry bottom boiler.		
2. Source Classification Code (SCC): 1-01-008-01		3. SCC Units: Tons Burned
4. Maximum Hourly Rate: 83.7	5. Maximum Annual Rate: 733,292	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: See Comment	8. Maximum % Ash: 0.7	9. Million Btu per SCC Unit: 27.6, HHV
10. Segment Comment: Fuel data shown above is based on design data for petcoke at a 22.2-percent blend by weight with PRB coal and a boiler heat input of 7,475 MMBtu/hr. Data will vary depending on coal/petcoke characteristics and coal/petcoke blend ratio. Maximum sulfur content of coal/petcoke blends will vary with petcoke and coal heat content but will not exceed 3.46 lb SO₂/MMBtu.		

EMISSIONS UNIT INFORMATION

Section [1] of [6]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 3 of 3

1. Segment Description (Process/Fuel Type): ULSD fuel oil combusted in pulverized coal dry bottom boiler.		
2. Source Classification Code (SCC): 1-01-005-01		3. SCC Units: Thousand Gallons Burned
4. Maximum Hourly Rate: 10.9	5. Maximum Annual Rate: 3,000	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash: 0.01	9. Million Btu per SCC Unit: 137, HHV
10. Segment Comment: ULSD fuel oil used during startups, shutdowns, malfunctions, when placing pulverizers in and out of service, and for flame stability.		

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:		

EMISSIONS UNIT INFORMATION

Section [1] of [6]

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
1 – NO _x	204 and 205	139	EL
2 – SO ₂	067		EL
3 – PM	017	146	EL
4 – PM ₁₀	017	146	EL
5 – CO	204 and 205		EL
6 – VOC	204 and 205		EL
7 – SAM	067	146	EL
8 – HCl (H106)	067	146	NS
9 – HF (H107)	067	146	EL
10 – Hg (H114)	204, 205, and 206	139, 017, 067, and 146	EL
11 – HAPS	204, 205, and 206	139, 017, 067, and 146	NS

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control:	
3. Emissions: 373.8 lb/hour 1,637 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.05 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [6]

POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.050 lb/MM Btu	4. Equivalent Allowable Emissions: 373.8 lb/hour 1,637 tons/year
5. Method of Compliance: NO_x CEMS – 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 373.8 lb/hr	4. Equivalent Allowable Emissions: 373.8 lb/hour N/A tons/year
5. Method of Compliance: NO_x CEMS – 24-hour block average (6 a.m. to 6 a.m.); see Section 5.1.2	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart Da	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 1.0 lb/MW, gross	4. Equivalent Allowable Emissions: 800 lb/hour 3,504 tons/year
5. Method of Compliance: NO_x CEMS – 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60.44Da(e)(1)	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO₂		2. Total Percent Efficiency of Control:	
3. Emissions: 411.1 lb/hour 1,310 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.055 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.040 lb/MM Btu	4. Equivalent Allowable Emissions: 299.0 lb/hour 1,310 tons/year
5. Method of Compliance: SO₂ CEMS – 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions **2** of **3**

1. Basis for Allowable Emissions Code: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 411.1 lb/hr	4. Equivalent Allowable Emissions: 411.1 lb/hour N/A tons/year
5. Method of Compliance: SO₂ CEMS – 24-hour block average (6 a.m. to 6 a.m.); see Section 5.1.2	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions **3** of **3**

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart Da	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 1.4 lb/MW, gross	4. Equivalent Allowable Emissions: 1,120 lb/hour 4,906 tons/year
5. Method of Compliance: SO₂ CEMS – 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60.43Da(i)(1)(i)	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control:	
3. Emissions: 97.2 lb/hour	Potential Emissions: 426 tons/year	4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.013 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years		
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.013 lb/MM Btu	4. Equivalent Allowable Emissions: 97.2 lb/hour 426 tons/year
5. Method of Compliance: Stack Test – EPA Reference Methods 5 or 17	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart Da	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.14 lb/MW, gross	4. Equivalent Allowable Emissions: 112 lb/hour 491 tons/year
5. Method of Compliance: Stack Test – EPA Reference Methods 5 or 17	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60.42Da(c)(1)	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM₁₀		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 183.3 lb/hour 803 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.025 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years		
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.025 lb/MM Btu	4. Equivalent Allowable Emissions: 183.3 lb/hour 803 tons/year
5. Method of Compliance: Stack Test – EPA Reference Methods 201 or 201A, and 202	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 1,121.3 lb/hour 4,911 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.15 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.15 lb/MM Btu	4. Equivalent Allowable Emissions: 1,121.3 lb/hour 4,911 tons/year
5. Method of Compliance: CO CEMS – 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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

1. Basis for Allowable Emissions Code: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.13 lb/MM Btu	4. Equivalent Allowable Emissions: 971.8 lb/hour N/A tons/year
5. Method of Compliance: Stack Test – EPA Reference Method 10	
6. Allowable Emissions Comment (Description of Operating Method): Applicable when firing only coal. Rule 62-212.400(4)(c), F.A.C.	

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):	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 26.9 lb/hour 118 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0036 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0036 lb/MM Btu	4. Equivalent Allowable Emissions: 26.9 lb/hour 118 tons/year
5. Method of Compliance: Stack Test – EPA Reference Methods 18, and 25 or 25A	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SAM		2. Total Percent Efficiency of Control:	
3. Emissions: 29.9 lb/hour	Potential Emissions: 131 tons/year	4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0040 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years		
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0040 lb/MM Btu	4. Equivalent Allowable Emissions: 29.9 lb/hour 131 tons/year
5. Method of Compliance: Stack Test – EPA Reference Methods 8, 8A, or 8B	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: HCL (H106)		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 33.7 lb/hour 148 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0046 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years		
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

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

Allowable Emissions Allowable Emissions of N/A

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: Hg (H114)		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.0066 lb/hour 0.029 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 8.1×10^{-6} lb/ MWh Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years		
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 - NSPS Subpart Da	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 20×10^{-6} lb / MWh, gross (bituminous) 66×10^{-6} lb / MWh, gross (subbituminous)	4. Equivalent Allowable Emissions: 0.016 lb/hour 0.07 tons/year (bituminous)
5. Method of Compliance: Hg CEMS – Annual Average	
6. Allowable Emissions Comment (Description of Operating Method): Limits are prorated for bituminous/subbituminous coal blends 40 CFR 60.45Da(a)	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: HAPs		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 42.0 lb/hour 184 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: AP-42 Reference: ECT, 2007, Sargent & Lundy, 2007		7. Emissions Method Code: 3 and 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [6]

POLLUTANT DETAIL INFORMATION

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F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -**ALLOWABLE EMISSIONS – N/A**

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

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):	

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):	

EMISSIONS UNIT INFORMATION

Section [1] of [6]

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

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: 60 min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. Rule 62-210.700(1), F.A.C.	

EMISSIONS UNIT INFORMATION

Section [1] of [6]

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: 40 CFR 60.42Da(b).	

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:	

EMISSIONS UNIT INFORMATION

Section [1] of [6]

H. CONTINUOUS MONITOR INFORMATION**Complete if this emissions unit is or would be subject to continuous monitoring.****Continuous Monitoring System:** Continuous Monitor 1 of 5

1. Parameter Code: EM	2. Pollutant(s): NO_x
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: Required by 40 CFR 60 and 75. Specific NO_x CEMS information will be provided to FDEP when available.	

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: O₂ or CO₂	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: NO_x diluent CEM requirements of 40 CFR 60 and 75. Specific O₂ CEMS information will be provided to FDEP when available.	

EMISSIONS UNIT INFORMATION

Section [1] of [6]

H. CONTINUOUS MONITOR INFORMATION**Complete if this emissions unit is or would be subject to continuous monitoring.****Continuous Monitoring System:** Continuous Monitor 3 of 5

1. Parameter Code: EM	2. Pollutant(s): Hg
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: Required by 40 CFR 60, Subpart Da. Specific Hg CEMS information will be provided to FDEP when available.	

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code: EM	2. Pollutant(s): CO
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: BACT required monitoring. Specific CO CEMS information will be provided to FDEP when available.	

EMISSIONS UNIT INFORMATION

Section [1] of [6]

H. CONTINUOUS MONITOR INFORMATION**Complete if this emissions unit is or would be subject to continuous monitoring.****Continuous Monitoring System:** Continuous Monitor 5 of 5

1. Parameter Code: EM	2. Pollutant(s): SO₂
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: Required by 40 CFR 60 and 75. Specific SO₂ CEMS information will be provided to FDEP when available.	

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:	

EMISSIONS UNIT INFORMATION

Section [1] of [6]

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: <u>Section 2.0</u> ☐ 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: <u>Section 2.0</u>
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: <u>Section 2.0</u> ☐ 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) ☒ 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: <u>Sections 1.0 – 10.0</u> ☐ Not Applicable

EMISSIONS UNIT INFORMATION

Section [1] of [6]

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: Section 5.0 ☐ 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: Section 6.0 ☐ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) To be provided to FDEP when available. ☐ Attached, Document ID: _____ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications **NOT APPLICABLE**

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____
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
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NO _x Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NO _x Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable

EMISSIONS UNIT INFORMATION

Section [1] of [6]

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [2] of [6]

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:
Auxiliary team boiler fired with ultra low sulfur diesel (ULSD) fuel oil.

3. Emissions Unit Identification Number: **002 (Auxiliary Boiler)**

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes ☒ No

9. Package Unit:
Manufacturer: _____ Model Number: _____

10. Generator Nameplate Rating: **MW**

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [2] of [6]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

NO_x, CO, and VOC

Low NO_x Burners (LNB [Control Device Code 205]

PM, PM₁₀, SO₂, H₂SO₄ Mist, HCl and HF

Ultra Low Sulfur Diesel (ULSD) Fuel Oil

2. Control Device or Method Code(s): **205**

EMISSIONS UNIT INFORMATION

Section [2] of [6]

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: N/A
2. Maximum Production Rate: N/A
3. Maximum Heat Input Rate: 375 million Btu/hr, HHV
4. Maximum Incineration Rate: N/A pounds/hr tons/day
5. Requested Maximum Operating Schedule: hours/day weeks/year days/week 876 hours/year
6. Operating Capacity/Schedule Comment:

EMISSIONS UNIT INFORMATION

Section [2] of [6]

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: 35		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 200 feet	7. Exit Diameter: 7.0 feet	
8. Exit Temperature: 595 °F	9. Actual Volumetric Flow Rate: 159,100 acfm	10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates Zone: 17 East (km): 261.50 North (km): 3,330.52		14. Emission Point Latitude/Longitude N/A Latitude (DD/MM/SS) N/A Longitude (DD/MM/SS)	
15. Emission Point Comment: Emission point coordinate datum is North American Datum 1927 (NAD 27)			

EMISSIONS UNIT INFORMATION

Section [2] of [6]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment **1** of **1**

1. Segment Description (Process/Fuel Type): Distillate fuel oil combusted in an industrial boiler.		
2. Source Classification Code (SCC): 1-02-005-01		3. SCC Units: Thousand Gallons Burned
4. Maximum Hourly Rate: 2.72	5. Maximum Annual Rate: 2,380	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash: 0.01	9. Million Btu per SCC Unit: 138, HHV
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:		

EMISSIONS UNIT INFORMATION

Section [2] of [6]

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
1 – NO _x	205		EL
2 – SO ₂			EL
3 – PM			EL
4 – PM ₁₀			EL
5 – CO	205		EL
6 – VOC	205		EL
7 – SAM			EL
8 – HCl (H106)			EL
9 – HF (H107)			NS

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 33.8 lb/hour 14.8 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.09 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Auxiliary boiler will have a maximum capacity factor of 10 percent (i.e., 876 hours per year at design capacity)			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.09 lb/MM Btu	4. Equivalent Allowable Emissions: 33.8 lb/hour 14.8 tons/year
5. Method of Compliance: Stack Test – EPA Reference Method 7E	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart Db	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.20 lb/MMBtu	4. Equivalent Allowable Emissions: 75.0 lb/hour N/A tons/year
5. Method of Compliance: Stack Test – EPA Reference Method 7E.	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 60.44b(a)(1)(ii)	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.6 lb/hour 0.3 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0016 lb/MMBtu Reference: ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Auxiliary boiler will have a maximum capacity factor of 10 percent (i.e., 876 hours per year at design capacity).			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: 0.6 lb/hour 0.3 tons/year
5. Method of Compliance: Fuel oil analysis for sulfur content	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM₁₀		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 8.6 lb/hour 3.8 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.023 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years		
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Auxiliary boiler will have a maximum capacity factor of 10 percent (i.e., 876 hours per year at design capacity).			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.023 lb/MMBtu	4. Equivalent Allowable Emissions: 8.6 lb/hour 3.8 tons/year
5. Method of Compliance: Stack Test – EPA Reference Methods 5 or 17	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE – NESHAPS Subpart DDDDD	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.03 lb/MMBtu	4. Equivalent Allowable Emissions: 11.3 lb/hour N/A tons/year
5. Method of Compliance: Stack Test – EPA Reference Methods 5 or 17	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 63, Subpart DDDDD, Table 1	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 30.0 lb/hour 13.1 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.08 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Auxiliary boiler will have a maximum capacity factor of 10 percent (i.e., 876 hours per year at design capacity).			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.08 lb/MMBtu	4. Equivalent Allowable Emissions: 30.0 lb/hour 13.1 tons/year
5. Method of Compliance: Stack Test – EPA Reference Method 10	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE – NESHAPS Subpart DDDDD	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 400 ppmvd @ 3% O₂	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Stack Test – EPA Reference Method 10	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 63, Subpart DDDDD, Table 6.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 2.0 lb/hour 0.9 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0054 lb/MMBtu Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Auxiliary boiler will have a maximum capacity factor of 10 percent (i.e., 876 hours per year at design capacity).			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0054 lb/MMBtu	4. Equivalent Allowable Emissions: 2.0 lb/hour 0.9 tons/year
5. Method of Compliance: Stack Test – EPA Reference Methods 18, and 25 or 25A	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SAM		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Neg. lb/hour Neg. tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Auxiliary boiler sulfuric acid mist emissions resulting from the combustion of ULSD fuel oil will be negligible.			
11. Potential, Fugitive, and Actual Emissions Comment: Auxiliary boiler will have a maximum capacity factor of 10 percent (i.e., 876 hours per year at design capacity).			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Fuel oil analysis for sulfur content	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: HCL [H106]		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Neg. lb/hour Neg. tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Auxiliary boiler hydrochloric acid emissions resulting from the combustion of ULSD fuel oil will be negligible.			
11. Potential, Fugitive, and Actual Emissions Comment: Auxiliary boiler will have a maximum capacity factor of 10 percent (i.e., 876 hours per year at design capacity).			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE – NESHAPS Subpart DDDDD	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0009 lb/MMBtu	4. Equivalent Allowable Emissions: 0.34 lb/hour N/A tons/year
5. Method of Compliance: Stack Test – EPA Reference Method 26 or 26A	
6. Allowable Emissions Comment (Description of Operating Method): 40 CFR 63, Subpart DDDDD, Table 1	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: HF [H107]		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Neg. lb/hour Neg. tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Auxiliary boiler hydrofluoric acid emissions resulting from the combustion of ULSD fuel oil will be negligible.			
11. Potential, Fugitive, and Actual Emissions Comment: Auxiliary boiler will have a maximum capacity factor of 10 percent (i.e., 876 hours per year at design capacity).			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Fuel oil analysis for sulfur content	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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):	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

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: 60 min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. Rule 62-210.700(1), F.A.C.	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: 40 CFR 63, Subpart DDDDD	

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:	

EMISSIONS UNIT INFORMATION

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H. CONTINUOUS MONITOR INFORMATION – N/A**Complete 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:	

EMISSIONS UNIT INFORMATION

Section [2] of [6]

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: Section 2.0 ☐ 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: Section 2.0
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: Section 2.0 ☐ 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) ☒ 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: Sections 1.0 – 10.0 ☐ Not Applicable

EMISSIONS UNIT INFORMATION

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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: Section 5.0 ☐ 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: Section 6.0 ☐ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) To be provided to FDEP when available. ☐ Attached, Document ID: _____ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications **NOT APPLICABLE**

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____
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
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable

EMISSIONS UNIT INFORMATION

Section [2] of [6]

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [3] of [6]

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:

20-cell mechanical draft cooling tower. Tower is equipped with drift eliminators for control of PM/PM₁₀ emissions.

3. Emissions Unit Identification Number: **003 (Cooling Tower)**

4. Emissions Unit Status Code:
C

5. Commence Construction Date:
N/A

6. Initial Startup Date:
N/A

7. Emissions Unit Major Group SIC Code:
49

8. Acid Rain Unit?
☐ Yes
☒ No

9. Package Unit:
Manufacturer:

Model Number:

10. Generator Nameplate Rating: **MW**

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [3] of [6]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Drift eliminators – High Velocity (Velocity > 250 ft/min) [Control Device Code 014]

2. Control Device or Method Code(s): **014**

EMISSIONS UNIT INFORMATION

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B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: 334,920 gal/min
2. Maximum Production Rate: N/A
3. Maximum Heat Input Rate: N/A million Btu/hr,
4. Maximum Incineration Rate: N/A 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: Field 1 maximum process rate is the cooling tower water recirculation rate.

EMISSIONS UNIT INFORMATION

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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: 18		2. Emission Point Type Code: 3	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Cooling tower consists of 20 cells.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V		6. Stack Height: 60 feet	
		7. Exit Diameter: 32.5 feet	
8. Exit Temperature: 100 °F		9. Actual Volumetric Flow Rate: 1,283,200 acfm	
		10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates Zone: East (km): N/A North (km): N/A		14. Emission Point Latitude/Longitude N/A Latitude (DD/MM/SS) N/A Longitude (DD/MM/SS)	
15. Emission Point Comment: Cooling tower consists of 20 cells with 20 individual exhaust fans. Stack height and diameter data provided in Fields 6 and 7 are for each cell. Exhaust volume and temperature will vary with ambient temperatures.			

EMISSIONS UNIT INFORMATION

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D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment **1** of **1**

1. Segment Description (Process/Fuel Type): Cooling Tower – Process Cooling, Mechanical Draft		
2. Source Classification Code (SCC): 3-85-001-01		3. SCC Units: Million Gallons Throughput
4. Maximum Hourly Rate: 20.1	5. Maximum Annual Rate: 176,034	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
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:		

EMISSIONS UNIT INFORMATION

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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
1 – PM	014		NS
2 – PM₁₀	014		NS

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 16.8 lb/hour 73.5 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: AP-42, ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0005-percent drift loss	4. Equivalent Allowable Emissions: 16.8 lb/hour 73.5 tons/year
5. Method of Compliance: Cooling tower vendor design data	
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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM₁₀		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 0.3 lb/hour 1.1 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: AP-42, ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [3] of [6]

POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0005-percent drift loss	4. Equivalent Allowable Emissions: 0.3 lb/hour 1.1 tons/year
5. Method of Compliance: Cooling tower vendor design data	
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):	

EMISSIONS UNIT INFORMATION

Section [3] of [6]

G. VISIBLE EMISSIONS INFORMATION

Complete 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: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Rule 62-296.320(4)(b), F.A.C.	

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:	

EMISSIONS UNIT INFORMATION

Section [3] of [6]

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: <u>Section 2.0</u> ☐ 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: _____ ☒ Not Applicable
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: <u>Section 2.0</u> ☐ 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) ☒ 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: <u>Sections 1.0 – 10.0</u> ☐ Not Applicable

EMISSIONS UNIT INFORMATION

Section [3] of [6]

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: Section 5.0 ☐ 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: Section 6.0 ☐ 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 **NOT APPLICABLE**

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____
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
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable

EMISSIONS UNIT INFORMATION

Section [3] of [6]

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [4] of [6]

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:

Emergency generator diesel engine fired with ultra low sulfur diesel (ULSD) fuel oil.

3. Emissions Unit Identification Number: **004 (Emergency Generator Diesel Engine)**

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes ☒ No

9. Package Unit:

Manufacturer:

Model Number:

10. Generator Nameplate Rating: **1.64 MW**

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [4] of [6]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

NO_x, CO, and VOC

Diesel engine design

PM, PM₁₀, SO₂, H₂SO₄ Mist, HCl and HF

Ultra Low Sulfur Diesel (ULSD) Fuel Oil

2. Control Device or Method Code(s):

EMISSIONS UNIT INFORMATION

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B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: N/A
2. Maximum Production Rate: N/A
3. Maximum Heat Input Rate: 18.3 million Btu/hr
4. Maximum Incineration Rate: N/A pounds/hr tons/day
5. Requested Maximum Operating Schedule: hours/day days/week weeks/year 96 hours/year
6. Operating Capacity/Schedule Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.

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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: 38		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V		6. Stack Height: 20 feet	
7. Exit Diameter: 1.3 feet		8. Exit Temperature: 855 °F	
9. Actual Volumetric Flow Rate: 9,700 acfm		10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates Zone: East (km): N/A North (km): N/A		14. Emission Point Latitude/Longitude N/A Latitude (DD/MM/SS) N/A Longitude (DD/MM/SS)	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

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D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment **1** of **1**

1. Segment Description (Process/Fuel Type): Emergency generator diesel engine fired with distillate fuel oil		
2. Source Classification Code (SCC): 2-01-001-02		3. SCC Units: Thousand Gallons Burned
4. Maximum Hourly Rate: 0.13	5. Maximum Annual Rate: 12.7	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash: 0.01	9. Million Btu per SCC Unit: 138
10. Segment Comment: Fuel flow estimated based on engine rating of 2,309 hp and assumed heat rate of 7,900 Btu/hp-hr.		

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:		

EMISSIONS UNIT INFORMATION

Section [4] of [6]

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
1 – NO _x			EL
2 – SO ₂			EL
3 – PM			EL
4 – PM ₁₀			EL
5 – CO			EL
6 – VOC			EL
7 – SAM			NS
8 – HF (H107)			NS

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control:	
3. Emissions: 21.7 lb/hour	Potential Emissions: 1.0 tons/year	4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 6.0 grams per kilowatt-hour (g/kWh) Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 6.4 g/kWh	4. Equivalent Allowable Emissions: 21.7 lb/hour 1.0 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Limit in Field 3 is for NO_x + NMHC per NSPS Subpart IIII Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 6.4 g/kWh	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Limit in Field 3 is for NO_x + NMHC per NSPS Subpart IIII	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.03 lb/hour 0.0014 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0079 g/kWh Reference: ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: 0.03 lb/hour 0.0014 tons/year
5. Method of Compliance: Fuel oil analysis for sulfur content	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM₁₀		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.7 lb/hour 0.04 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.20 g/kWh Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.20 g/kWh	4. Equivalent Allowable Emissions: 0.7 lb/hour 0.04 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.20 g/kWh	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
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):	

EMISSIONS UNIT INFORMATION

Section [4] of [6]

POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)****Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 12.7 lb/hour 0.6 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 3.5 g/kWh Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.5 g/kWh	4. Equivalent Allowable Emissions: 12.7 lb/hour 0.6 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.5 g/kWh	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 1.4 lb/hour 0.07 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.4 g/kWh Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -**ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 6.4 g/kWh	4. Equivalent Allowable Emissions: 1.4 lb/hour 0.07 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Limit in Field 3 is for NO_x + NMHC per NSPS Subpart IIII Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 6.49 g/kWh	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Limit in Field 3 is for NO_x + NMHC per NSPS Subpart IIII Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SAM		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Neg. lb/hour Neg. tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Emergency generator diesel engine sulfuric acid mist emissions resulting from the combustion of ULSD fuel oil will be negligible.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Fuel oil analysis for sulfur content	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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):	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: HF [H107]		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Neg. lb/hour Neg. tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Emergency generator diesel engine hydrofluoric acid mist emissions resulting from the combustion of ULSD fuel oil will be negligible.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Fuel oil analysis for sulfur content	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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):	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

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: 60 min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. Rule 62-210.700(1), F.A.C.	

EMISSIONS UNIT INFORMATION
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H. CONTINUOUS MONITOR INFORMATION – N/A

Complete 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:	

EMISSIONS UNIT INFORMATION

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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: <u>Section 2.0</u> ☐ 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: <u>Section 2.0</u> ☐ Not Applicable
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: <u>Section 2.0</u> ☐ 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) ☒ 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: <u>Sections 1.0 – 10.0</u> ☐ Not Applicable

EMISSIONS UNIT INFORMATION

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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: Section 5.0 ☐ 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: Section 6.0 ☐ 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 **NOT APPLICABLE**

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____
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
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable

EMISSIONS UNIT INFORMATION

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Additional Requirements Comment

EMISSIONS UNIT INFORMATION

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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:

Emergency firewater pump diesel engine fired with ultra low sulfur diesel (ULSD) fuel oil.

3. Emissions Unit Identification Number: **005 (Emergency Firewater Pump Diesel Engine)**

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes ☒ No

9. Package Unit:

Manufacturer:

Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

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Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

NO_x, CO, and VOC

Diesel engine design

PM, PM₁₀, SO₂, H₂SO₄ Mist, HCl and HF

Ultra Low Sulfur Diesel (ULSD) Fuel Oil

2. Control Device or Method Code(s):

EMISSIONS UNIT INFORMATION

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B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Process or Throughput Rate: N/A
2. Maximum Production Rate: N/A
3. Maximum Heat Input Rate: 3.3 million Btu/hr
4. Maximum Incineration Rate: N/A pounds/hr tons/day
5. Requested Maximum Operating Schedule: hours/day days/week weeks/year 96 hours/year
6. Operating Capacity/Schedule Comment: Excluding operations during emergency conditions, the emergency firewater pump diesel engine will operate up to 96 hours per year for routine testing and maintenance.

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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: 52		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V		6. Stack Height: 12 feet	
		7. Exit Diameter: 0.5 feet	
8. Exit Temperature: 845 °F		9. Actual Volumetric Flow Rate: 1,800 acfm	
		10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates Zone: East (km): N/A North (km): N/A		14. Emission Point Latitude/Longitude N/A Latitude (DD/MM/SS) N/A Longitude (DD/MM/SS)	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

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D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Emergency firewater pump diesel engine fired with distillate fuel oil		
2. Source Classification Code (SCC): 2-02-001-02		3. SCC Units: Thousand Gallons Burned
4. Maximum Hourly Rate: 0.024	5. Maximum Annual Rate: 2.3	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash: 0.01	9. Million Btu per SCC Unit: 138
10. Segment Comment: Fuel flow estimated based on engine rating of 432 hp and assumed heat rate of 7,700 Btu/hp-hr.		

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:		

EMISSIONS UNIT INFORMATION

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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
1 – NO_x			EL
2 – SO₂			EL
3 – PM			EL
4 – PM₁₀			EL
5 – CO			EL
6 – VOC			EL
7 – SAM			NS
8 – HF (H107)			NS

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 1.9 lb/hour 0.09 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 2.0 grams per horsepower-hour (g/hp-hr) Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years		
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.0 g/hp-hr	4. Equivalent Allowable Emissions: 1.9 lb/hour 0.09 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Limit in Field 3 is for NO_x + NMHC per NSPS Subpart IIII Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.0 g/hp-hr	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Limit in Field 3 is for NO_x + NMHC per NSPS Subpart IIII Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO₂		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.005 lb/hour 0.0002 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0054 g/hp-hr Reference: ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: 0.005 lb/hour 0.0002 tons/year
5. Method of Compliance: Fuel oil analysis for sulfur content	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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):	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)****Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM₁₀		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.14 lb/hour 0.007 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.15 g/hp-hr Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.15 g/hp-hr	4. Equivalent Allowable Emissions: 0.14 lb/hour 0.007 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.15 g/hp-hr	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 2.5 lb/hour 0.12 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 2.6 g/hp-hr Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years		
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 2.6 g/hp-hr	4. Equivalent Allowable Emissions: 2.5 lb/hour 0.12 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 2.6 g/hp-hr	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 1.0 lb/hour 0.05 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 1.0 g/hp-hr Reference: Sargent & Lundy, 2007		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.0 g/hp-hr	4. Equivalent Allowable Emissions: 1.0 lb/hour 0.05 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Limit in Field 3 is for NO_x + NMHC per NSPS Subpart IIII Rule 62-212.400(4)(c), F.A.C.	

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

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.0 g/hp-hr	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart IIII	
6. Allowable Emissions Comment (Description of Operating Method): Limit in Field 3 is for NO_x + NMHC per NSPS Subpart IIII Rule 62-212.400(4)(c), F.A.C.	

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):	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)****Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions**

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SAM		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Neg. lb/hour Neg. tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: ECT, 2007.		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Emergency firewater pump diesel engine sulfuric acid mist emissions resulting from the combustion of ULSD fuel oil will be negligible.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Fuel oil analysis for sulfur content.	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: HF [H107]		2. Total Percent Efficiency of Control:	
3. Potential Emissions: Neg. lb/hour Neg. tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: ECT, 2007		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Emergency firewater pump diesel engine hydrofluoric acid mist emissions resulting from the combustion of ULSD fuel oil will be negligible.			
11. Potential, Fugitive, and Actual Emissions Comment: Excluding operations during emergency conditions, the emergency generator diesel engine will operate up to 96 hours per year for routine testing and maintenance.			

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -**ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 % S fuel oil	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Fuel oil analysis for sulfur content	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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):	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

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: 60 min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. Rule 62-210.700(1), F.A.C.	

EMISSIONS UNIT INFORMATION

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H. CONTINUOUS MONITOR INFORMATION – N/A**Complete 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:	

EMISSIONS UNIT INFORMATION

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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: Section 2.0 ☐ 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: Section 2.0 ☐ Not Applicable
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: Section 2.0 ☐ 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) ☒ 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: Sections 1.0 – 10.0 ☐ Not Applicable

EMISSIONS UNIT INFORMATION

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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: <u>Section 5.0</u> ☐ 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: <u>Section 6.0</u> ☐ 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 **NOT APPLICABLE**

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____
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
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable

EMISSIONS UNIT INFORMATION

Section [5] of [6]

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [6] of [6]

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:

Solid fuel, limestone, and byproduct material handling and storage systems

3. Emissions Unit Identification Number: **006 (Material Handling)**

4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes ☒ No

9. Package Unit:

Manufacturer:

Model Number:

10. Generator Nameplate Rating: **MW**

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

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Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Fabric Filters - Low Temperature (< 180°F) [Control Device/Method Code 018]

Process Enclosure [Control Device/Method Code 054]

Dust Suppression By Water Sprays [Control Device/Method Code 061]

**Dust Suppression By Chemical Stabilizers or Wetting Agents
[Control Device/Method Code 062]**

Dust Suppression By Physical Stabilization [Control Device/Method Code 106]

Dust Suppression – Traffic Control [Control Device/Method Code 108]

2. Control Device or Method Code(s): **018, 054, 061, 062, 106, and 108**

EMISSIONS UNIT INFORMATION

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B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: Section 2.0
2. Maximum Production Rate: N/A
3. Maximum Heat Input Rate: N/A million Btu/hr,
4. Maximum Incineration Rate: N/A 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: Material handling and storage system throughput rates are discussed in Section 2.0.

EMISSIONS UNIT INFORMATION

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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: N/A		2. Emission Point Type Code: 3 and 4	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Solid fuel, limestone and byproduct material handling and storage systems including material transfer, storage silos and piles, and vehicular traffic on paved and unpaved roads.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: F and V		6. Stack Height: N/A feet	
7. Exit Diameter: N/A feet			
8. Exit Temperature: 77 °F		9. Actual Volumetric Flow Rate: N/A acfm	
10. Water Vapor: N/A %			
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates Zone: East (km): N/A North (km): N/A		14. Emission Point Latitude/Longitude N/A Latitude (DD/MM/SS) N/A Longitude (DD/MM/SS)	
15. Emission Point Comment: Information regarding the material handling point source stack parameters is provided in Appendix A.			

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D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment **1** of **6**

1. Segment Description (Process/Fuel Type): Solid Fuel (Coal and Petcoke) Handling		
2. Source Classification Code (SCC): 3-05-101-03		3. SCC Units: Tons Transferred
4. Maximum Hourly Rate: 3,000	5. Maximum Annual Rate: 3,303,079	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

Segment Description and Rate: Segment **2** of **6**

1. Segment Description (Process/Fuel Type): Limestone Handling		
2. Source Classification Code (SCC): 3-05-101-05		3. SCC Units: Tons Transferred
4. Maximum Hourly Rate: 21.3	5. Maximum Annual Rate: 186,505	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

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D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment **3** of **6**

1. Segment Description (Process/Fuel Type): Fly Ash Handling		
2. Source Classification Code (SCC): 3-05-101-98		3. SCC Units: Tons Transferred
4. Maximum Hourly Rate: 33.5	5. Maximum Annual Rate: 293,460	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

Segment Description and Rate: Segment **4** of **6**

1. Segment Description (Process/Fuel Type): Bottom Ash Handling		
2. Source Classification Code (SCC): 3-05-101-98		3. SCC Units: Tons Transferred
4. Maximum Hourly Rate: 8.5	5. Maximum Annual Rate: 74,460	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment **5** of **6**

1. Segment Description (Process/Fuel Type): Gypsum Handling		
2. Source Classification Code (SCC): 3-05-101-98		3. SCC Units: Tons Transferred
4. Maximum Hourly Rate: 35.5	5. Maximum Annual Rate: 310,980	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

Segment Description and Rate: Segment **6** of **6**

1. Segment Description (Process/Fuel Type): Wastewater Treatment Solids (ZLD Brine)		
2. Source Classification Code (SCC): 3-05-101-98		3. SCC Units: Tons Transferred
4. Maximum Hourly Rate: 1.5 to 2.75	5. Maximum Annual Rate: 13,140 to 24,090	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

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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
1 – PM	018, 054, 061, 062, 106, and 108		NS
2 – PM ₁₀	018, 054, 061, 062, 106, and 108		NS

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 7.8 lb/hour 34.3 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: AP-42, ECT, 2007		7. Emissions Method Code: 3	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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: RULE (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: Best Management Practices (BMPs)	4. Equivalent Allowable Emissions: 7.8 lb/hour 34.3 tons/year
5. Method of Compliance: Implementation of BMPs to control fugitive and non-fugitive PM from material handling and storage systems.	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE - NSPS Subpart OOO	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.022 gr / dscf	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year
5. Method of Compliance: Stack Test – EPA Reference Method 5	
6. Allowable Emissions Comment (Description of Operating Method): NSPS Subpart OOO – Limestone stack emissions	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM₁₀		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 2.3 lb/hour 10.3 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: N/A Reference: AP-42, ECT, 2007.		7. Emissions Method Code: 3	
8.a. Baseline Actual Emissions (if required): N/A tons/year		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): N/A tons/year		9.b. Projected Monitoring Period: N/A ☐ 5 years ☐ 10 years	
10. Calculation of Emissions: Detailed emission calculations are provided in Appendix A.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [6] of [6]

POLLUTANT DETAIL INFORMATION

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete 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 (BACT)	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: Best Management Practices (BMPs)	4. Equivalent Allowable Emissions: 2.3 lb/hour 10.3 tons/year
5. Method of Compliance: Implementation of BMPs to control fugitive and non-fugitive PM₁₀ from material handling and storage systems.	
6. Allowable Emissions Comment (Description of Operating Method): Rule 62-212.400(4)(c), F.A.C.	

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):	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Rule 62-296.320(4)(b), F.A.C. NSPS Subpart Y – Coal Handling and Storage	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: VE7	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 7 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: NSPS Subpart OOO – Limestone stack emissions	

EMISSIONS UNIT INFORMATION

Section [6] of [6]

G. VISIBLE EMISSIONS INFORMATION**Visible Emissions Limitation:** Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: NSPS Subpart OOO – Limestone fugitive emissions	

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:	

EMISSIONS UNIT INFORMATION

Section [6] of [6]

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: Section 2.0 ☐ 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: _____ ☒ Not Applicable
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: Section 2.0 ☐ 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) ☒ 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: Sections 1.0 – 10.0 ☐ Not Applicable

EMISSIONS UNIT INFORMATION

Section [6] of [6]

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: Section 5.0 ☐ 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: Section 6.0 ☐ 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 **NOT APPLICABLE**

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____
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
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NO _x Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NO _x Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable

EMISSIONS UNIT INFORMATION

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Additional Requirements Comment

APPENDIX C
DISPERSION MODELING FILES

Taylor Energy Center
Class I Area Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
A. Taylor Energy Center Runs			
CALPUFF/PUFF-INP	3	TECYY.INP YY = 01 - 03	CALPUFF input files
CALPUFF/PUFF-OUT	3	TECYY.CON	CALPUFF output concentration files
	3	TECYYP1.CON	CALPUFF output concentration files, NO ₃ /HNO ₃ Repartition
	3	TECYYP2.CON	CALPUFF output concentration files, PM ₁₀ , 3-Hour SO ₂ , Visibility Species Processing
	3	TECDFYY.CON	CALPUFF output concentration files, dry deposition flux files
	3	TECWFYY.CON	CALPUFF output concentration files, wet deposition flux files
	3	TECYYTDEP.CON	CALPUFF output concentration files, total wet and dry deposition flux files
	3	TECYY.LST YY = 01 - 03	CALPUFF output concentration list files
Subtotal Files	21		
CALPUFF/POST-UTIL	3	POSTTECYYA.INP	POSTUTIL input files, NO ₃ /HNO ₃ Repartition
	3	POSTTECYYB.INP	POSTUTIL input, PM ₁₀ , 3-Hour SO ₂ , Visibility Species Processing
	3	POSTTECYYB.INP	POSTUTIL input, PM ₁₀ , 3-Hour SO ₂ , Visibility Species Processing
	3	TECYYP1.LST	POSTUTIL output list files, NO ₃ /HNO ₃ Repartition
	3	TECYYP2.LST	POSTUTIL output list files, PM ₁₀ , 3-Hour SO ₂ , Visibility Species Processing
	3	TECYYTDEP.LST	POSTUTIL output list files, total wet and dry deposition flux files
		YY = 01 - 03	
Subtotal Files	18		
CALPUFF/POST-INP	3	TECYYNBRB.POI	CALPOST input NO ₂ files - Bradwell Bay NWA
	3	TECYYPBRB.POI	CALPOST input PM ₁₀ files - Bradwell Bay NWA
	3	TECYYSBRB.POI	CALPOST input SO ₂ files - Bradwell Bay NWA
	3	TECYYNDBRB.POI	CALPOST input nitrogen deposition files - Bradwell Bay NWA
	3	TECYYSDRB.POI	CALPOST input sulfur deposition files - Bradwell Bay NWA
	3	TECYYNSTM.POI	CALPOST input NO ₂ files - St. Marks NWA
	3	TECYYPSTM.POI	CALPOST input PM ₁₀ files - St. Marks NWA
	3	TECYYSSTM.POI	CALPOST input SO ₂ files - St. Marks NWA
	3	TECYYNDSTM.POI	CALPOST input nitrogen deposition files - St. Marks NWA
	3	TECYYSDSTM.POI	CALPOST input sulfur deposition files - St. Marks NWA
	3	TECYYVSTMB.POI	CALPOST input visibility files; Method 2 - St. Marks NWA
	3	TECYYVSTMC.POI	CALPOST input visibility files; Method 6 - St. Marks NWA
	3	TECYYNCHA.POI	CALPOST input NO ₂ files - Chassahowitzka NWA
	3	TECYYPCHA.POI	CALPOST input PM ₁₀ files - Chassahowitzka NWA
	3	TECYYSCA.POI	CALPOST input SO ₂ files - Chassahowitzka NWA
	3	TECYYNDCHA.POI	CALPOST input nitrogen deposition files - Chassahowitzka NWA
	3	TECYYSDCHA.POI	CALPOST input sulfur deposition files - Chassahowitzka NWA
	3	TECYYVCHAB.POI	CALPOST input visibility files; Method 2 - Chassahowitzka NWA
	3	TECYYVCHAC.POI	CALPOST input visibility files; Method 6 - Chassahowitzka NWA
	3	TECYYNOKE.POI	CALPOST input NO ₂ files - Okefenokee NWA
	3	TECYYPOKE.POI	CALPOST input PM ₁₀ files - Okefenokee NWA
	3	TECYYSOKE.POI	CALPOST input SO ₂ files - Okefenokee NWA
	3	TECYYNDOKE.POI	CALPOST input nitrogen deposition files - Okefenokee NWA
	3	TECYYSDOKE.POI	CALPOST input sulfur deposition files - Okefenokee NWA
	3	TECYYVOKEB.POI	CALPOST input visibility files; Method 2 - Okefenokee NWA
	3	TECYYVOKEC.POI	CALPOST input visibility files; Method 6 - Okefenokee NWA
	3	TECYYNWFI.POI	CALPOST input NO ₂ files - Wolf Island NWA
	3	TECYYPWFI.POI	CALPOST input PM ₁₀ files - Wolf Island NWA
	3	TECYYSWFI.POI	CALPOST input SO ₂ files - Wolf Island NWA
	3	TECYYNDWFI.POI	CALPOST input nitrogen deposition files - Wolf Island NWA
	3	TECYYSDWFI.POI	CALPOST input sulfur deposition files - Wolf Island NWA
	3	TECYYVWFI.POI	CALPOST input visibility files; Method 2 - Wolf Island NWA
	3	TECYYVWFI.POI	CALPOST input visibility files; Method 6 - Wolf Island NWA
		YY = 01 - 03	
Subtotal Files	99		

Taylor Energy Center
Class I Area Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
A. Taylor Energy Center Runs			
CALPUFF/POST-OUT	3	TECYNO2BRB.POL	CALPOST output NO ₂ files - Bradwell Bay NWA
	3	TECYPM10BRB.POL	CALPOST output PM ₁₀ files - - Bradwell Bay NWA
	3	TECYSO2BRB.POL	CALPOST output SO ₂ files - - Bradwell Bay NWA
	3	TECYNDBRB.POL	CALPOST output nitrogen deposition files - Bradwell Bay NWA
	3	TECYSDBRB.POL	CALPOST output sulfur deposition files - Bradwell Bay NWA
	3	TECYNO2STM.POL	CALPOST output NO ₂ files - St. Marks NWA
	3	TECYPM10STM.POL	CALPOST output PM ₁₀ files - - St. Marks NWA
	3	TECYSO2STM.POL	CALPOST output SO ₂ files - - St. Marks NWA
	3	TECYNDSTM.POL	CALPOST output nitrogen deposition files - St. Marks NWA
	3	TECYSDSTM.POL	CALPOST output sulfur deposition files - St. Marks NWA
	3	TECYVSTMB.POL	CALPOST output visibility files; Method 2 - St. Marks NWA
	3	TECYVSTMC.POL	CALPOST output visibility files; Method 6 - St. Marks NWA
	3	TECYNO2CHA.POL	CALPOST output NO ₂ files - Chassahowitzka NWA
	3	TECYPM10CHA.POL	CALPOST output PM ₁₀ files - - Chassahowitzka NWA
	3	TECYSO2CHA.POL	CALPOST output SO ₂ files - - Chassahowitzka NWA
	3	TECYNDCHA.POL	CALPOST output nitrogen deposition files - Chassahowitzka NWA
	3	TECYSDCHA.POL	CALPOST output sulfur deposition files - Chassahowitzka NWA
	3	TECYVCHAB.POL	CALPOST output visibility files; Method 2 - Chassahowitzka NWA
	3	TECYVCHAC.POL	CALPOST output visibility files; Method 6 - Chassahowitzka NWA
	3	TECYNO2OKE.POL	CALPOST output NO ₂ files - Okefenokee NWA
	3	TECYPM10OKE.POL	CALPOST output PM ₁₀ files - - Okefenokee NWA
	3	TECYSO2OKE.POL	CALPOST output SO ₂ files - - Okefenokee NWA
	3	TECYNDKE.POL	CALPOST output nitrogen deposition files - Okefenokee NWA
	3	TECYSDKE.POL	CALPOST output sulfur deposition files - Okefenokee NWA
	3	TECYVKEB.POL	CALPOST output visibility files; Method 2 - Okefenokee NWA
	3	TECYVKEC.POL	CALPOST output visibility files; Method 6 - Okefenokee NWA
	3	TECYNO2WFI.POL	CALPOST output NO ₂ files - Wolf Island NWA
	3	TECYPM10WFI.POL	CALPOST output PM ₁₀ files - - Wolf Island NWA
	3	TECYSO2WFI.POL	CALPOST output SO ₂ files - - Wolf Island NWA
	3	TECYNDWFI.POL	CALPOST output nitrogen deposition files - Wolf Island NWA
	3	TECYSDWFI.POL	CALPOST output sulfur deposition files - Wolf Island NWA
	3	TECYVWFI.POL	CALPOST output visibility files; Method 2 - Wolf Island NWA
	3	TECYVWFI.POL	CALPOST output visibility files; Method 6 - Wolf Island NWA
		YY = 01 - 03	
Subtotal Files	99		
Total Files	240		

Source: ECT, 2007.

Taylor Energy Center
Class I Area Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
B. Taylor Energy Center Cumulative SO₂ Runs			
CALPUFF/PUFF-INP	3	SO2CYY.INP	CALPUFF input files, SO ₂ consuming sources
	3	SO2EYY.INP	CALPUFF input files, SO ₂ expanding sources
	3	MBSIGSO2YY.INP YY = 01 - 03	CALPUFF input files, Taylor Energy Center Main Boiler, SIL Receptors
Subtotal Files	9		
CALPUFF/PUFF-OUT	3	SO2CYY.CON	CALPUFF output files, SO ₂ consuming sources
	3	SO2EYY.CON	CALPUFF output files, SO ₂ expanding sources
	3	MBSIGSO2YY.CON	CALPUFF output files, Taylor Energy Center Main Boiler, SIL Receptors
	3	TSO2YY.CON	CALPUFF output files, SO ₂ cumulative 24-Hour
	3	TSO23HYY.CON	CALPUFF output files, SO ₂ cumulative 3-Hour
	3	SO2CYY.LST	CALPUFF output list files, SO ₂ consuming sources
	3	SO2EYY.LST	CALPUFF output list files, SO ₂ expanding sources
	3	MBSIGSO2YY.LST YY = 01 - 03	CALPUFF output list files, Taylor Energy Center Main Boiler, SIL Receptors
Subtotal Files	24		
CALPUFF/CALSUM	3	YYSUM.INP	CALSUM input files, SO ₂ cumulative 24-Hour
	3	YYSUM.LST	CALSUM output list files, SO ₂ cumulative 24-Hour
	3	YY3HSUM.INP	CALSUM input files, SO ₂ cumulative 3-Hour
	3	YY3HSUM.LST YY = 01 - 03	CALSUM output list files, SO ₂ cumulative 3-Hour
Subtotal Files	12		
CALPUFF/POST-INP	3	TSO2YYBRB.POI	CALPOST input SO ₂ files - - Bradwell Bay NWA 24-Hour Cumulative
	3	TSO2YYSTM.POI YY = 01 - 03	CALPOST input SO ₂ files - - St. Marks NWA 24-Hour Cumulative
	2	TSO2YYOKE.POI	CALPOST input SO ₂ files - - Okefenokee NWA 24-Hour Cumulative
	2	T3HSO2YYBRB.POI YY = 02, 03	CALPOST input SO ₂ files - - Bradwell Bay NWA 3-Hour Cumulative
	3	T3HSO2YYSTM.POI YY = 01 - 03	CALPOST input SO ₂ files - - St. Marks NWA 3-Hour Cumulative
Subtotal Files	13		
CALPUFF/POST-OUT	3	TSO2YYBRB.POL	CALPOST input SO ₂ files - - Bradwell Bay NWA 24-Hour Cumulative
	3	TSO2YYSTM.POL YY = 01 - 03	CALPOST input SO ₂ files - - St. Marks NWA 24-Hour Cumulative
	2	TSO2YYOKE.POL	CALPOST input SO ₂ files - - Okefenokee NWA 24-Hour Cumulative
	2	T3HSO2YYBRB.POL YY = 02, 03	CALPOST input SO ₂ files - - Bradwell Bay NWA 3-Hour Cumulative
	3	T3HSO2YYSTM.POL YY = 01 - 03	CALPOST input SO ₂ files - - St. Marks NWA 3-Hour Cumulative
Subtotal Files	13		
Total Files	71		

Source: ECT, 2007.

**Taylor Energy Center
Class II Dispersion Modeling File List**

Directory Name	No. of Files	File Name	File Description
AERMOD MET DATA	5	TLHTLHYY.PFL	Meteorological Data - Tallahassee/Municipal Airport profile files
	5	TLHTLHYY.SFC YY = 01 - 05	Meteorological Data - Tallahassee/Municipal Airport surface files
Subtotal Files	10		
GEP	1	tecver2.bpl	Building Profile Input Program (BPIP) input file
	1	tecver2.pro	Building Profile Input Program (BPIP) output file
Subtotal Files	2		
AERMOD Input/Output Files			
SO ₂ - 3 Hour	5	3HS02YY.ADI	AERMOD input files
	5	3HS02YY.ADO YY = 01 - 05	AERMOD output files
SO ₂ - 24 Hour	5	24HS02YY.ADI	AERMOD input files
	5	24HS02YY.ADO YY = 01 - 05	AERMOD output files
SO ₂ - Annual	5	ANNS02YY.ADI	AERMOD input files
	5	ANNS02YY.ADO YY = 01 - 05	AERMOD output files
NO _x - Annual	5	ANNNOXYY.ADI	AERMOD input files
	5	ANNNOXYY.ADO YY = 01 - 05	AERMOD output files
CO - 1 Hour & 8 Hour	5	COYYYY.ADI	AERMOD input files
	5	COYYYY.ADO YYYY = 2001 - 2005	AERMOD output files
PM ₁₀ - 24-Hour & Annual	5	PMMYY.ADI	AERMOD input files (3 km receptor grid)
	5	PMMYY.ADO YY = 01 - 05	AERMOD output files (3 km receptor grid)
	1	PM05A.ADI	AERMOD input file (4 km receptor grid for 2005 only)
	1	PM05A.ADO	AERMOD output file (4 km receptor grid for 2005 only)
PM ₁₀ - 24-Hour & Annual (100-meter grid at max. impact receptor)	5	PMMIYY.ADI	AERMOD input files
	5	PMMIYY.ADI YY = 01 - 05	AERMOD output files
Subtotal files	72		
AERMOD Receptor Files			
AERMOD Receptor Grid (SO ₂ , NO _x , CO Analyses)	1	TECSO2.ROU	
AERMOD Receptor Grid (PM ₁₀ Analysis)	1	TECPM.ROU	3 km grid, 200-meter receptor spacing
AERMOD Receptor Grid (PM ₁₀ Analysis)	1	TECPM05.ROU	4 km grid, 200-meter receptor spacing
AERMOD Receptor Grid (PM ₁₀ PSD Class II Increment and NAAQS Analyses)	1	TECMI.ROU	400 meter grid, 100-meter receptor spacing centered on maximum impact receptor location.
Subtotal files	4		
Total Files	88		

APPENDIX D

CLASS I AREA NATIONAL VISIBILITY IMPAIRMENT ANALYSES

APPENDIX D

ASSESSMENT OF METEOROLOGY FOR DAYS HAVING ELEVATED PREDICTED VISIBILITY IMPACTS IN THE CLASS 1 AREAS

In some instances, the actual meteorological conditions would result in much lower visibility than the background visibility assumed by the CALPUFF model. Those same conditions, on which the model meteorological inputs were at least partially based, may have led to higher predicted impacts (i.e., as a result of high relative humidity, etc.). The acceptability of a source's impacts is defined as the predicted degradation in visibility, i.e., the difference in background conditions versus the change caused by the source. If the predicted impacts are compared to an artificially low background visibility extinction coefficient, then the model results may be worse than could occur given the actual conditions. This appendix contains a discussion of the meteorology on those days with predicted visibility impacts greater than the FLAG guidance of 5-percent increase in the Beta extinction coefficient.

For evaluating the meteorology on days with elevated predicted visibility impacts, historical data were obtained from the National Oceanic and Atmospheric Administration (NOAA). The following types of data were relied upon to develop an understanding of the conditions on the days in question:

- Raw surface data in SCRAM format for the Tallahassee Regional Airport (TLH).
- Local climatological data (LCD) summarizing surface observations at the following airports:
 - Tallahassee Regional Airport (call sign TLH).
 - Perry Foley Airport (call sign 40J).
 - Apalachicola Municipal Airport (call sign AAF).
 - Jacksonville International Airport (call sign JAX).
 - Waycross–Ware County Airport (call sign AYS).
- NEXRAD national mosaic reflectivity images.
- NOAA hourly precipitation data reports.

LCDs are available by month for the individual stations. These are especially useful since they show reported sky and weather conditions (where available), temperature, dew point, and relative humidity (RH). Obscuring phenomena, such as mist and fog, which restrict visibility, are not directly accounted for in the CALPUFF model. The SCRAM data for individual stations were sometimes used as a check, since that data should reflect the LCDs. The TLH is located approximately 20 statute miles (sm) north of the St. Marks National Wilderness Area (NWA). The Perry Foley Airport is located approximately 25 sm directly east of the St. Marks NWA. The AAF is located approximately 45 sm southwest of the St. Marks NWA. Jacksonville is located approximately 30 sm east southeast of the Okefenokee NWA, and Waycross–Ware County Airport is located approximately 15 miles north northwest of the Okefenokee NWA.

NEXRAD data is based on Doppler radar, and is combined and processed to show areas of cloud and precipitation for the entire United States. Historical hourly radar images were available for the days of interest.

Monthly precipitation reports for Florida and Georgia were acquired from NOAA for the months and years of interest. These contained hourly observation of precipitation for all stations in the state. The precipitation stations nearest to the St. Marks NWA are Monticello in Jefferson County, Tallahassee in Leon County, and Woodruff Dam in Gadsden County. The Monticello station is approximately 30 sm northeast of the St. Marks NWA. The Tallahassee station is approximately 20 sm north of the St. Marks NWA. The Woodruff Dam station is approximately 30 sm northwest of the St. Marks NWA. In relation to the St. Marks NWA, Monticello station is located north-northeast, Tallahassee is north, and Woodruff Dam is northwest of the NWA. The precipitation stations closest to the Okefenokee NWA are Fargo in Clinch County, and Folkston in Charlton County. Fargo is approximately 7 sm to the west of the Okefenokee NWA, and Folkston is approximately 10 sm east and in the same County as the NWA.

The following sections of this appendix contain brief descriptions of the meteorology that occurred in the vicinity of the affected Class I areas on each of the days in question. The table shown below is a list of the days and the results of the meteorological review.

Section	Date (mm/dd/yyyy)	Julian Day	Affected Class I Area	Natural Reduced Visibility
D-1	08/02/2001	214	St. Marks NWA	Yes
D-2	09/08/2001	251	St. Marks NWA	Yes
D-3	09/20/2001	263	St. Marks NWA	Yes
D-4	11/23/2001	327	St. Marks NWA	Yes
D-5	12/17/2001	351	St. Marks NWA	Yes
D-6	01/28/2002	28	St. Marks NWA	Yes
D-7	02/11/2002	42	St. Marks NWA	No
D-8	06/01/2002	152	St. Marks NWA	No
D-9	08/31/2002	243	St. Marks NWA	Yes
D-10	10/14/2002	287	St. Marks NWA	Yes
D-11	10/24/2002	297	St. Marks NWA	Yes
D-12	10/26/2002	299	St. Marks NWA	Yes
D-13	11/25/2002	329	St. Marks NWA	No
D-14	11/26/2002	330	St. Marks NWA	No
D-15	12/11/2002	345	St. Marks NWA	No
D-16	03/05/2003	64	St. Marks NWA	Yes
D-17	03/16/2003	75	St. Marks NWA	No
D-18	03/29/2003	88	St. Marks NWA	Yes
D-19	08/16/2003	228	St. Marks NWA	No
D-20	10/11/2003	284	St. Marks NWA	Yes
D-21	11/23/2003	327	St. Marks NWA	No
D-22	02/08/2001	39	Okefenokee NWA	No
D-23	06/08/2002	159	Okefenokee NWA	Yes

<u>Section</u>	<u>Date (mm/dd/yyyy)</u>	<u>Julian Day</u>	<u>Affected Class I Area</u>	<u>Natural Reduced Visibility</u>
D-24	11/27/2002	331	Okefenokee NWA	No
D-25	01/22/2003	22	Okefenokee NWA	Yes
D-26	02/01/2003	32	Okefenokee NWA	No
D-27	02/04/2003	35	Okefenokee NWA	Yes

SECTION D-1

Affected Area: St. Marks NWA

Date: August 2, 2001 (Julian Day 214)

Surface Observations

TLH reported light rain for 2 hours (0.04 inch each hour) and trace amount during another hour on this day. Fog and haze were also reported, but visibility is generally reported as unlimited. There were 10 hours during which the RH was above 90 percent.

AAF reported precipitation as trace for 3 hours and 0.01-inch accumulation for another hourly period. RH was 90 percent or above for half of the day. Visibility is generally reported as being unlimited.

Perry-Foley Airport reported no precipitation on this day. RH was 90 percent or higher for 13 hours during the day.

NEXRAD

The radar images show a large area of reflectance encompassing the TEC Site and St. Marks NWA. The area starts out fairly clear around midnight, showing increasing reflectance the rest of the day, and starting to clear gradually by 9 p.m.

Precipitation Stations

Monticello's data for the month of August is reported as being deleted. Tallahassee reported 0.07 inch of rain, and no precipitation was reported at the Woodruff Dam station.

Summary

The measured rain at Tallahassee and the prevalence of reflectance during most hours of this day indicate that visibility would likely have been reduced for at least some hours in the St. Marks NWA.

SECTION D-2

Affected Area: St. Marks NWA

Date: September 8, 2001 (Julian Day 251)

Surface Observations

TLH reported trace rain for 1 hour during the day. Visibility was generally reported as unlimited. The highest RH reported was 97 percent for a single hour.

AAF reported a 0.01-inch accumulation of rain during a single hour. Mist and average visibilities of 6 sm occurred for 5 hours of the day. The highest RH value reported were 97 percent for 5 hours of the day.

Perry-Foley Airport reported a 0.32 inch of rain. RH was reported as above 90 percent for 14 hours of the day. Weather conditions and visibility data are not reported.

NEXRAD

The radar images showing reflectance ranging from clear to solid over and near the TEC Site and St. Marks NWA. The coverage is sporadic throughout the day.

Precipitation Stations

Monticello reported 0.1 inch of rain, Tallahassee reported trace rain, and no precipitation was reported at the Woodruff Dam station.

Summary

There were some conditions that may have led to decreased visibility in the St. Marks NWA, mainly shown by the NEXRAD images.

SECTION D-3

Affected Area: St. Marks NWA

Date: September 20, 2001 (Julian Day 263)

Surface Observations

TLH reported mist and reduced visibilities of 6 sm or less for 7 hours in the early morning (midnight to 8 a.m.). The highest RH of 97 percent was reported for 1 hour of the day.

AAF reported a total of 0.56-inch accumulation occurring in 2 separate hours, and an hour of trace rain. Heavy rain was reported for 3 hours of the day, followed by 5 hours of rain and light rain. Mist and fog were also reported during the hours of rain along with reduced visibilities ranging from 0.5 to 7 sm. During the hours preceding and following the rain events, visibility was generally unlimited.

Perry-Foley Airport reported no precipitation and RH above 90 percent for half of the day. Visibility and weather condition data are not reported.

NEXRAD

The radar images show limited areas of reflectance sporadically passing over the St. Marks NWA throughout the day.

Precipitation Stations

No precipitation was reported by the Monticello, Tallahassee, and Woodruff Dam stations.

Summary

The combination of the precipitation data for AAF, and the NEXRAD images, it appears likely that there were some periods of reduced visibility in the St. Marks NWA.

SECTION D-4

Affected Area: St. Marks NWA

Date: November 23, 2001 (Julian Day 327)

Surface Observations

TLH reported light rain in the first few hours of the day, followed by 13 hours of heavy rain for a total accumulation reported was 1.71 inches. Mist and fog were reported for the major part of the day. Reduced visibility as low as 0.5 sm were reported throughout the day. RH ranged from 93 to 100 percent throughout of the day.

AAF reported a total of 1.11 inches accumulation throughout the day, as well as several hours of trace rain. Rain was reported for the major part of the day, accompanied by mist and fog. Visibility of 4 sm or less was reported for 3 hours. RH was reported as 90 percent or above, except for a 1-hour period at 87 percent.

Perry-Foley Airport reported a 0.62-inch accumulation of rain throughout the day, and 19 hours of RH values above 90 percent. Visibility and weather conditions data are not reported.

NEXRAD

The radar images show a large area of reflectance encompassing the TEC Site and St. Marks NWA. The area remains constantly dense throughout most of the day, starting to clear out around 8 p.m. This is consistent with the significant precipitation reported at both the Monticello station in Jefferson County and the Tallahassee station in Leon County, as well as at the TLH and the AAF.

Precipitation Stations

Monticello reported 0.7 inch of rain, Tallahassee reported 1.71 inches of rain, and 1.2 inches of precipitation was reported at Woodruff Dam.

Summary

It is evident from the available data that the region, including the St. Marks NWA, experienced rain and reduced visibilities.

SECTION D-5

Affected Area: St. Marks NWA

Date: December 17, 2001 (Julian Day 351)

Surface Observations

TLH reported mist for most of the early morning (i.e., till 8 a.m.) with some reduced visibility during the period. RH ranged from 90 to 100 percent during this period. No precipitation was reported.

AAF had 1 hour of reportable precipitation accompanied by mist, and a total of 0.36 inch of accumulation for the day. Average visibilities during this hour were generally reported as 3 sm or lower. Unlimited visibility was reported for the remainder of the hours.

Perry-Foley Airport reported a 0.24-inch accumulation of rain over a single hourly period. RH values were above 90 percent for 8 hours of the day. Weather conditions and visibility data were not reported.

NEXRAD

The radar images show a clear area from midnight until 3 p.m., when a large area of reflectance moves towards northern Florida which encompasses the TEC Site and St. Marks NWA.

Precipitation Stations

The data at Monticello was excluded as being suspect. Tallahassee reported 0.26 inch of rain, and 0.1 inch of precipitation was reported at Woodruff Dam.

Summary

Given the large amount of rain reported for at Tallahassee, Woodruff Dam, and AAF, it is reasonable to assume that it may have rained in St. Marks, although for only a limited number of hours. This speculation is further supported by the NEXRAD data.

SECTION D-6

Affected Area: St. Marks NWA

Date: January 28, 2002 (Julian Day 28)

Surface Observations

The Perry Foley airport had 15 hours of reportable precipitation and 0.75-inch total precipitation. All hours in the afternoon had reported precipitation. There were 7 hours with 100-percent RH. Sky conditions and visibility were not reported at this site.

TLH only reported light rain for 2 hours during the day. There were 12 hours during which fog and/or mist were reported, along with 8 hours of 100 percent RH. Also, there were 7 hours with visibility reported to be 1 sm or less. The SCRAM data is generally consistent with the LCD for this station.

AAF reported 19 hours of fog and/or mist. A total of 16 hours had reported visibilities of 1 sm or less. Also, 100-percent RH was reported during half of the hours that day. Precipitation was reported as trace for 1 hour, and 0.01 inch of accumulation for another hourly period.

NEXRAD

The radar images show a large area of reflectance encompassing the TEC Site and St. Marks NWA. The area is fairly solid at midnight and gradually thins by 4 a.m. Eastern Standard Time (EST). By 7 a.m. the area has cleared, and remains so for the rest of the day. This is somewhat inconsistent with the precipitation data reported at the Perry Foley Airport, but may be the result of fewer more localized showers.

Precipitation Stations

Monticello reported 0.1 inch of rain, a trace amount of precipitation was reported at the Tallahassee site, and nothing was reported at the Woodruff Dam station.

Summary

From the data reviewed above, it is reasonable to conclude that the conditions at St. Marks NWA were similar to the surrounding stations. Fog, mist, and possibly rain probably occurred for much of January 28, 2002.

SECTION D-7

Affected Area: St. Marks NWA

Date: February 11, 2002 (Julian Day 42)

Surface Observations

TLH reported no precipitation. Mist and smoke were reported beginning at 11:53 p.m. through midnight. During this period visibility was reported as 2.5 to 5 sm.

AAF had no reportable precipitation or visibility reducing conditions on this day.

Perry-Foley Airport reported a 0.01-inch accumulation of rain over a 1-hour period. RH was below 90 percent for most of the day. Visibility and weather condition data were not reported.

NEXRAD

The radar images show a clear area throughout the entire day with the exception of the first hour, when a relatively large area of reflectance partly encompasses the TEC Site and St. Marks NWA.

Precipitation Stations

No precipitation was reported by the Monticello, Tallahassee, and Woodruff Dam stations.

Summary

Based on the available data, it is not likely that meteorological conditions existed that would have restricted visibility at the St. Marks NWA.

SECTION D-8

Affected Area: St. Marks NWA

Date: June 1, 2002 (Julian Day 152)

Surface Observations

TLH reported no precipitation or other visibility reducing conditions on this the day.

AAF had no reportable precipitation or visibility reducing conditions throughout the entire day.

Perry-Foley Airport reported no precipitation on this day. RH was reported as 100 percent in the early morning and for the last hour of the day. RH was generally below 90 percent during most of the daylight hours. Visibility and weather conditions data were not reported.

NEXRAD

The radar images show a clear area throughout most of the day with the exception of 2 to 3 evening hours, when a relatively small area of reflectance partly encompasses the TEC Site and St. Marks NWA.

Precipitation Stations

No precipitation was reported for either the Monticello or Tallahassee stations. The data is reported as having been deleted at the Woodruff Dam stations.

Summary

Of the meteorological data reviewed, there is nothing to suggest that visibility was restricted in the St. Marks NWA on this day.

SECTION D-9

Affected Area: St. Marks NWA

Date: August 31, 2002 (Julian Day 243)

Surface Observations

TLH reported 0.04 inch of precipitation over a 2-hour period, along with 3 hours with trace amounts of rain. Rain and mist were reported during 3 hours of the day. The RH was reported to be above 90 percent for 9 hours during the day.

AAF reported 2.63 inches of rain with measurable amounts occurring for 12 hours from 4 a.m. to 4 p.m. Also, trace amounts of precipitation were recorded between the hours of 1 a.m. and 4 a.m. Rain (sometimes heavy), fog, and mist were reported throughout the most of the day, accompanied by RH levels at 90 percent or above.

Perry-Foley Airport reported 0.84 inch of precipitation, which occurred during 2 hours on this day. There were 18 hours where RH was reported at or above 90 percent. Visibility and significant weather condition data were not reported.

NEXRAD

The radar images show a significant area of reflectance which encompasses the TEC Site and St. Marks NWA throughout most of the day. The area starts out relatively clear at midnight, becoming denser around 3 a.m. and starting to gradually clear out after 4 p.m.

Precipitation Stations

The station at Monticello reported 1.0 inch of rain, and the Tallahassee station had a reported precipitation of 0.04 inch. No precipitation was reported for the Woodruff Dam station.

Summary

Given the conditions on this day, especially those reported at AAF, it is likely that meteorological conditions restricting visibility occurred for most hours in the day.

SECTION D-10

Affected Area: St. Marks NWA

Date: October 14, 2002 (Julian Day 287)

Surface Observations

TLH reported 0.42 inch of precipitation, most of which occurred over the last 3 hours of the day as thunderstorms. There was an additional hour of measurable precipitation (i.e., 0.01 inch) and 2 hours of trace amounts of rain. The RH was reported to be above 90 percent for several hours in the early and late hours of the day.

AAF reported light rain and mist throughout afternoon until 7 p.m. Rain was also reported between 10 p.m. and 11 p.m. Only a trace amount of rain was reported on this day. Also, the RH is above 90 percent throughout most of the day.

Perry-Foley Airport reported 0.44 inch of precipitation occurring mostly during the evening hours. RH values above 90 percent occurred for over half the day. Visibility and significant weather conditions were not reported.

NEXRAD

The radar images show a large area of reflectance which encompasses the TEC Site and St. Marks NWA throughout the day. The area starts out relatively complete at midnight, clears out for 2 hours during the day and gradually increases coverage for the rest of the day.

Precipitation Stations

Monticello reported 0.1 inch rain, Tallahassee had a reported precipitation of 0.42 inch, and 0.1 inch precipitation was reported by the Woodruff Dam station.

Summary

Based on the available data, it is likely that meteorological conditions that would reduce visibility existed for at least a portion of this day at the St. Marks NWA.

SECTION D-11

Affected Area: St. Marks NWA

Date: October 24, 2002 (Julian Day 297)

Surface Observations

TLH reported rain (sometimes heavy) and mist, with reduced visibility, for the first 7 hours of the day. A total of 0.17 inch of precipitation was reported to occur in the hours from midnight to 6 a.m. The RH was reported to be above 90 percent for the major part of the day.

AAF reported 0.06 inch of rain, including 2 hours of measurable amounts and 5 hours of trace amounts with several hours of trace rain occurring throughout the daylight hours. Mist was reported for 10 hours of the day. RH levels above 90 percent occurred for most of the day.

Perry-Foley Airport reported no precipitation on this day. RH values of 90 percent or above were reported for more than half of the day. Visibility and weather condition data were not reported.

NEXRAD

No images were recorded for October 24, 2002.

Precipitation Stations

Monticello reported 0.6 inch of rain, Tallahassee had a reported precipitation of 0.16 inch, and 0.3 inch of precipitation was reported for the Woodruff Dam station.

Summary

Given the prevalence of rain and mist, it is likely that visibility-reducing conditions also existed at the St. Marks NWA on this day.

SECTION D-12

Affected Area: St. Marks NWA

Date: October 26, 2002 (Julian Day 299)

Surface Observations

TLH reported trace rain over a 5-hour period in the evening. Mist was reported to occur for 9 hours during the day and rain during 2 hours. These hours were also associated with reduced visibility. The RH exceeded 90 percent for most of the day.

AAF reported 0.01 inch of rain occurring between 7 p.m. and 9 p.m. Fog (sometimes heavy) and mist were reported until 9 a.m. The RH levels are reported to be above 90 percent for most of the day, with 5 hours of 100-percent RH.

Perry-Foley Airport reported no precipitation on this day. The RH levels are reported to be at or above 90 percent for 15 hours, with 7 hours of 100-percent RH. Significant weather conditions and visibility data were not reported.

NEXRAD

The radar images show a large area of reflectance in the vicinity of the TEC Site and St. Marks NWA, which gradually advances towards the site throughout the day and partially encompasses the site around 2 p.m.

Precipitation Stations

Monticello reported no precipitation, Tallahassee reported trace rain, and 0.4 inch of precipitation was reported by the Woodruff Dam station.

Summary

Given the prevalence of rain, fog, and mist, it is likely that conditions impairing visibility also existed at the St. Marks NWA on this day.

SECTION D-13

Affected Area: St. Marks NWA

Date: November 25, 2002 (Julian Day 329)

Surface Observations

TLH reported no rain throughout the day. Mist and fog were reported during a 3-hour period in the morning clearing by 10 a.m. The reported RH exceeds 90 percent in the hours before 9 a.m.

AAF reported a clear day, with the exception of an hourly period of rain resulting in a 0.01 inch of accumulation. This is somewhat inconsistent with the Doppler radar images for November 25, 2005, but may be result of fewer more localized showers.

Perry-Foley Airport reported no precipitation on this day. RH levels are reported to be above 90 percent for half of the day, with 3 hours of 100-percent RH. Visibility and significant weather condition data were not reported.

NEXRAD

The radar images show a clear area around the TEC Site and St. Marks NWA throughout the entire day.

Precipitation Stations

All three stations of Monticello, Tallahassee, and Woodruff Dam reported no precipitation, which is consistent with the images received from the Doppler radar.

Summary

Based on the available data, it is unlikely that meteorological conditions at St. Marks resulted in reduced visibility.

SECTION D-14

Affected Area: St. Marks NWA

Date: November 26, 2002 (Julian Day 330)

Surface Observations

TLH reported some fog, but visibility was good throughout the day. There was no recorded precipitation.

AAF reported no precipitation; however, some fog and haze were recorded.

Perry-Foley Airport reported no precipitation throughout the day. The RH values were reported to be above 90 percent for half of the day, with 3 hours of 100-percent RH. Visibility and significant weather condition data were not reported.

NEXRAD

The radar images show a clear area around the TEC Site and St. Marks NWA throughout the entire day.

Precipitation Stations

All three stations of Monticello, Tallahassee, and Woodruff Dam reported no precipitation, which is consistent with the images received from the Doppler radar.

Summary

Based on the available data, it is unlikely that meteorological conditions at St. Marks resulted in reduced visibility.

SECTION D-15

Affected Area: St. Marks NWA

Date: December 11, 2002 (Julian Day 345)

Surface Observations

TLH reported drizzle and misty conditions and 7 hours of trace rain, with no recorded accumulation. The recorded RH exceeded 90 percent for the initial half of the day.

AAF reported no precipitation throughout the day. Visibility was unlimited, except for 1 hour of haze, which restricted visibility to 2 sm. Some fog was also reported. The recorded RH values exceed 90 percent approximately half the day.

Perry-Foley Airport reported no precipitation for this day. RH values were reported to be above 90 percent for over half of the day, with 7 hours of 100-percent RH. Visibility values and significant weather condition data were not reported.

NEXRAD

The radar images show a large area of reflectance north of the TEC Site and St. Marks NWA, which gradually shifts further north. The area remains relatively clear throughout the day.

Precipitation Stations

Monticello has no reported precipitation, Tallahassee reports trace rain, and Woodruff Dam reports 0.1 inch of accumulation. This data is somewhat inconsistent with the images received from the Doppler radar, but it could be a result of more localized showers.

Summary

Based on the available data, it is unlikely that meteorological conditions at St. Marks resulted in reduced visibility.

SECTION D-16

Affected Area: St. Marks NWA

Date: March 5, 2003 (Julian Day 64)

Surface Observations

TLH reported rain, mist, and fog (sometimes heavy). TLH recorded precipitation of 0.07 inch. Most hours of the day experienced reduced visibilities, sometimes as low as 0.25 sm, for most of the day. At least 8 hours had visibility reported as 2 sm or less. The recorded RH exceeded 90 percent for a significant part of the day, registering 100-percent RH from midnight to 9:30 a.m.

AAF reported 0.05 inch of precipitation (measurable amounts for 2 hours), and 4 hours of trace amounts of precipitation. Fog (sometimes heavy) and mist lasted through most of the day. The recorded RH values exceeded 95 percent and visibility values were reported as 2 sm or less throughout much of the day.

Perry-Foley Airport reported no precipitation on this day. The RH values are above 90 percent for the entire day, with 8 hours of 100-percent RH. Visibility values and weather conditions were not reported.

NEXRAD

The radar images show a relatively clear day, with only minor area of reflectance encompassing the TEC Site and St. Marks from 11 a.m. to 4 p.m.

Precipitation Stations

Monticello and Woodruff Dam reported no precipitation on this day, while Tallahassee reported 0.07 inch of rain.

Summary

Given the weather conditions at TLH and AAF, it is reasonable to assume that visibility would have also been restricted at the St. Marks NWA.

SECTION D-17

Affected Area: St. Marks NWA

Date: March 16, 2003 (Julian Day 75)

Surface Observations

TLH reported rain and mist during 7 hours of the day. TLH reported 0.05 inch of precipitation occurring in the hours after 9 p.m. and continuing to the end of the day. There was in the early morning hours with reported mist and visibility less than or equal to 4 sm.

AAF reported 0.16 inch of precipitation consisting of 4 hours of measurable accumulation and 3 hours of trace accumulation. Mist lasted through much of the day. Reduced visibility was reported for over half of the day with several hours at 4-sm visibility or less.

Perry-Foley Airport reported no precipitation on this day. The RH values were reported to be above 90 percent for 10 hours of the day, with 8 hours of 100-percent RH. Weather conditions and visibility data were not reported.

NEXRAD

The radar images show a large area of reflectance located southwest of Florida, which gradually moves northeast throughout the day and encompasses the TEC Site and St. Marks NWA by around 8 p.m. The area of coverage remains dense throughout the rest of the day.

Precipitation Stations

Monticello has no records of precipitation, Tallahassee reported 0.07 inch of rain, and Woodruff Dam recorded no precipitation.

Summary

Based on the available data, there is some indication that St. Marks may have experienced meteorological conditions that would have resulted in reduced visibility on this day.

SECTION D-18

Affected Area: St. Marks NWA

Date: March 29, 2003 (Julian Day 88)

Surface Observations

TLH reported mist and fog through 9 a.m. TLH recorded 0.1 inch of rain with a 2-hour period of trace accumulation. Also, there was a 7-hour period with visibility values of 3 sm or lower, and 8 hours with RH values above 95 percent.

AAF reported 0.09 inch of precipitation and 4 hours with trace accumulation in the evening. During the first 9 hours of the day, fog and mist were prevalent, with reported visibility generally below 3 sm, and several values reported as low as 0.25 sm. RH values above 96 percent were recorded for 9 hours.

Perry-Foley Airport reported no precipitation throughout the day. RH values were reported to be above 90 percent for half of the day, with 5 hours of 100-percent RH. Weather conditions and visibility data were not reported.

NEXRAD

The radar images show a large reflectance area located west of Florida, which gradually moves east throughout the day and encompasses the TEC Site and St. Marks NWA around 7 p.m. The area is relatively clear throughout most of the day; however, the images indicate fairly complete coverage for the last few hours of the day.

Precipitation Stations

Monticello has no records of precipitation, Tallahassee reported 0.03 inch of rain, and Woodruff Dam recorded 0.1 inch.

Summary

Based on the available data, it is likely that meteorological conditions results in reduced visibility in the St. Marks NWA.

SECTION D-19

Affected Area: St. Marks NWA

Date: August 16, 2003 (Julian Day 228)

Surface Observations

TLH reported mist and fog throughout the first 7 hours of the day. Visibilities were reduced to of 3 sm or less during this period, and RH was above 95 percent. Also, TLH recorded 0.01 inch of rain by the end of this period. Thunderstorms were reported at approximately 8 p.m. in the evening, but they were probably distant since visibility was reported as 10 sm.

AAF reported no precipitation and overall good weather conditions throughout the day. The RH values were above 93 percent for the first 7 hours and the last 2 hours of the day. No visibility reducing conditions were reported.

The relevant data was missing from the Perry-Foley Airport on this day.

NEXRAD

No images were found for August 16, 2003.

Precipitation Stations

Monticello has no records of precipitation and Tallahassee reported 1.78 inches of rain, in contrast with the data received from the TLH. There are no records for the Woodruff Dam station.

Summary

Based on the available data, it cannot be concluded that there were any conditions that would have reduced visibility occurred in the St. Marks NWA.

SECTION D-20

Affected Area: St. Marks NWA

Date: October 11, 2003 (Julian Day 284)

Surface Observations

TLH reported thunderstorms during 1 hour, and rain and mist throughout the day. Reduced visibility for most of the day, with values of 5 sm or less reported for much of the day. RH above 90 percent occurred for every hour of the day, with most values above 95 percent. The recorded accumulation of precipitation was 1.78 inches.

AAF recorded 4.15 inches of rain on this day. Rain (sometimes heavy), with mist and/or fog, was reported rain throughout the day. All RH values were 94 percent or greater. Reduced visibility occurred for most of the day, with some values as low as 1 sm.

Perry-Foley Airport reported 0.91 inch of precipitation occurring during most hours of the day. RH values are reported to be above 94 percent for all hours of the day, with most hours reporting 100-percent RH. Weather conditions and visibility data were not reported.

NEXRAD

The radar images show a large area of reflectance encompassing the TEC Site and the St. Marks NWA. The area starts out fairly solid at midnight and remains fully covered throughout the day.

Precipitation Stations

Monticello reported 2.0 inches of precipitation, Tallahassee recorded 1.78 inches, and an accumulation of 1.0 inch of rain was reported at the Woodruff Dam station on this day. In general, the rain continued throughout the day at these stations.

Summary

Based on the data reviewed, it is highly likely that visibility in the St. Marks NWA was severely limited on this day.

SECTION D-21

Affected Area: St. Marks NWA

Date: November 23, 2003 (Julian Day 327)

Surface Observations

TLH reported fairly good weather conditions with good visibility and no precipitation. There were several hours with reported mist and fog early and late in the day. The RH values were above 90 percent for the first 9 hours and last 4 hours of the day.

AAF had no recorded precipitation. Mist and slightly reduced visibilities were reported between the hours of 4 a.m. and 9 a.m. The RH values were above 90 percent for the initial 8 hours of the day.

Perry-Foley Airport reported no precipitation on this day. The RH values were above 90 percent for most hours of the day, with 11 hours of 100-percent RH. Weather conditions and visibility data were not reported.

NEXRAD

The radar images show no significant area of reflectance in the vicinity of the TEC Site and the St. Marks NWA. The area starts out relatively clear at midnight and remains such throughout the day.

Precipitation Stations

Monticello had no recorded data of precipitation, and no precipitation was reported for the Tallahassee and Woodruff Dam stations.

Summary

Based on the available data, it cannot be concluded that there were any conditions that would have reduced visibility occurred in the St. Marks NWA.

SECTION D-22

Affected Class I Area: Okeefenokee NWA

Date: 8 Feb 2001 (Julian Day 39)

Surface Observations

No LCD data was available from Waycross–Ware County Airport on this day.

Jacksonville reported mist and fog in the early morning hours till 7 a.m. Visibility was poor during this period at 2 miles or less. Also, RH was consistently reported at 100 percent during this time; however, no precipitation was reported.

NEXRAD

No reflectance was shown in the vicinity of the Okeefenokee NWA on this day.

Precipitation Stations

No precipitation was reported at Folkston or Fargo on this day.

Summary

Fog and mist occurred during the first 7 hours of the day at the Jacksonville International Airport. Since no data was available for Waycross, it is uncertain how similar the conditions were.

SECTION D-23

Affected Class I Area: Okeefenokee NWA

Date: 8 June 2002 (Julian Day 159)

Surface Observations

No data was available from Waycross for this day.

At Jacksonville mist was reported for 1 hour in the morning (i.e., 5:56 a.m.). No precipitation was reported. RH ranged from 71 to 96 percent during the day.

NEXRAD

High levels of reflectance were shown to occur over the Okeefenokee NWA for most of the day indicating that rain was probable.

Precipitation Stations

The data from the Fargo station was deleted for this day, and no precipitation was indicated to occur at the Folkston station.

Summary

Based on the observations of reduced visibilities and 100-percent RH at Waycross, as well as the widespread reflectance in the over and around the Okeefenokee NWA, it can be concluded that visibility was impaired on this day.

SECTION D-24

Affected Class I Area: Okeefenokee NWA

Date: 27 Nov 2002 (Julian Day 331)

Surface Observations

Waycross reported 100-percent RH during 4 hours of the day. There were 3 hours with slightly diminished visibility (i.e., 5 miles).

No obscuring phenomena or precipitation were reported at Jacksonville on this day.

NEXRAD

No reflectance over or near the Okeefenokee NWA was shown on this day.

Precipitation Stations

No precipitation was reported at the Fargo or Folkston stations.

Summary

From the available data, it is not likely that the conditions would have resulted in any significant degradation of visibility.

SECTION D-25

Affected Class I Area: Okeefenokee NWA

Date: 22 Jan 2003 (Julian Day 22)

Surface Observations

Reduced visibility of 4 statute miles or less was reported from 5 p.m. through the rest of the day at the Waycross–Ware County Airport. RH was reported to be 100 percent from 1920 hours and continuing for the rest of the day. Also, there were 3 hours before 7 a.m. during which the relative humidity was 100 percent. Overcast conditions were reported during all but the first 2 hours of the day.

The Jacksonville airport, located approximately 30 sm east-southeast of the Okeefenokee NWA reported a total of 0.04 inch of rain on this day, with reportable or trace amounts on 5 hours. A total of 9 hours of rain and/or mist were reported. Overcast conditions were reported for over half of the day.

NEXRAD

This data is based on Doppler radar, and is combined and processed to show areas of cloud and precipitation for the entire United States. The radar images indicated scattered reflectance in the vicinity of the Okeefenokee NWA beginning 1100 EST through 1300, and again during the hours of 1600 through 2300. These images did not indicate heavy or widespread rainfall.

Precipitation Stations

The closest precipitation stations to the Okeefenokee NWA are Fargo just west of the NWA, and Folkston to the east. Fargo is located in Clinch County just east of the Okeefenokee NWA. Folkston is located in the same County (i.e., Charlton) as the Okeefenokee NWA. There was no reported precipitation at either of these sites on this day. Overcast conditions were reported for half of the hours.

Summary

From the data reviewed above, it is reasonable to conclude that the conditions at Okeefenokee NWA were similar to the surrounding stations. This would include fog, mist, and possibility some rain that would reduce visibility.

SECTION D-26

Affected Class I Area: Okeefenokee NWA

Date: 1 Feb 2003 (Julian Day 32)

Surface Observations

Waycross reported some reduced visibility before 4 a.m. However, rain may have occurred during these morning hours based on reported RH of 100 percent. Overcast conditions ended around 9 a.m. Jacksonville reported conditions with reduced visibility and mist until 5 a.m.

NEXRAD

No reflectance was shown to occur on this day in the vicinity of the Okeefenokee NWA.

Precipitation Stations

No precipitation was reported at the Folkston or Fargo stations.

Summary

Some weather phenomena that would restrict visibility in the early morning hours were indicated from the available data.

SECTION D-27

Affected Class I Area: Okeefenokee NWA

Date: 4 Feb 2003 (Julian Day 35)

Surface Observations

Waycross reported 100-percent RH during 4 hours of the day several hours of restricted visibility (i.e., 3 to 7 miles). Overcast conditions were reported until 12:21 p.m., and followed by clear sky conditions the remainder of the day.

Jacksonville reported rain at 7:56 a.m., and rain and mist between the hours of 8 a.m. and 11 a.m. with mist continuing and last reported at 1:19 p.m. Jacksonville reported a total of 0.21 inch of rain for the day. Visibility was reported to be severely limited at 2 miles or less between the hours of 10 a.m. and 1 p.m.

NEXRAD

No reflectance in the vicinity of the Okeefenokee NWA was shown to occur on this day.

Precipitation Stations

A total of 0.21 inch of precipitation during the 9 hours was reported at the Folkston station. No rain was reported at the Fargo station.

Summary

Weather phenomena that may have restricted visibility at the Okeefenokee NWA in the morning hours were evident from the available data.