Florida Department of
Environmental Protection

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January 18, 2007

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Mr. Randall R. LaBauve, Vice President
Environmental Services Department
Florida Power and Light Company (FPL)
700 Universe Avenue
Juno Beach, Florida 33408

Re: DEP File No. 0430017-001-AC (PSD-FL-385)
FPL Glades Power Park
Nominal 1,960 megawatt (MW) Solid Fuel-fired Power Plant

Dear Mr. LaBauve:

On December 19, 2006 we received your application for an Air Construction Permit pursuant to the Rules for the Prevention of Significant Deterioration (PSD Permit) to construct a solid fuel-fired power plant in the vicinity of Moore Haven, Glades County.

Pursuant to Rules 62-4.055, and 62-4.070 F.A.C., Permit Processing, the Department requests submittal of the additional information prior to processing the application. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Refer to the attached letter from the Federal Land Manager (Superintendent, Everglades and Dry Tortugas National Parks). The Department requires the same information as detailed therein. Also please document the contacts and consultations to-date about this project with the Vero Beach office of the U.S. Fish and Wildlife Service related to endangered species on site and in the environs of the proposed site.

2. General Electric and Conoco Phillips have described bituminous coal reference plants for Integrated Gasification and Combined Cycle (IGCC) units characterized by very low emissions. For example, the claimed emission values are 0.01 pounds per million Btu of heat input (lb/mmBtu) for sulfur dioxide (SO_2) and 0.02 lb/mmBtu for nitrogen oxides (NO_X). The assumptions for these cases are deep sulfur removal and selective catalytic reduction (SCR) to control emissions of SO_2 and NO_X. The provider's descriptions are available at:

   www.gasification.org/Docs/2005_Papers/29KEEL.pdf and

   www.iea-coal.org.uk/publishor/system/component_view.asp?LogDocId=81264&PhyDocId=5653

Please provide documentation of FPL's review of IGCC.

[Rule 62-210.200, F.A.C. (Definitions-BACT); Rule 62-212.400, F.A.C. (PSD and BACT)]

3. Are there future phases planned for the facility?

4. Very little information is provided regarding the characteristics of the air pollution control equipment in terms of vessel sizes, reagent use estimates, air to cloth ratios, electrostatic precipitator capacities (ESP fields), etc. Please update the information in the application with the most recent information available to FPL based on the present status of front end engineering design (FEED).
[Rule 62-210.070, F.A.C. (Standards for Issuing or Denying Permits)]

5. Please update the status of the mercury (Hg) control equipment design. Advise whether FPL will actually install another electrostatic precipitator (ESP) in front of the sorbent injection equipment and fabric filter. [Rule 62-070, F.A.C.]

6. Clarify the thermal cycle efficiency of the units given their designation as ultracritical pulverized coal units. The literature typically describes such technologies as capable of yielding efficiencies greater than 40 percent (%). Describe the basis for the efficiency estimate (e.g. net, higher heating value, semi-tropical conditions, etc.).

7. Include a mass balance calculation including a simplified process flow diagram depicting the approximate average Hg flows in and out of the process steps. The flows should include: Hg in the incoming fuel; the amount exiting via the ESP fly ash; the amount captured by sorbent injection and fabric filtration; the amount removed by the wet scrubber; and the amount exiting the stacks. Also describe any discharges via scrubber effluent to treatment or disposal.

8. According to the application, emissions of volatile organic compounds (VOC) are estimated to be 260 tons per year (TPY). Estimated emissions of NO_X are approximately 3,800 TPY. Please provide conduct an ambient impact analysis for ozone including the gathering of ambient air quality data.
[Rule 62-212(2)(e)1.e., F.A.C.; 40 CFR 52.21(i)(5)(i)(footnote 1)(July 1]

9. The maximum ambient concentrations predicted at ground level in Table 6-7 are all based on a single emission rate per pollutant irrespective of applicable averaging times. This analysis should be redone using the maximum emission values that will occur during the specified averaging times (i.e. 3-hour, 24-hour, annual, etc. as applicable) The information provided is insufficient to conclude that ambient monitoring is not required for the pollutants and related averaging times given in Rule 62-212.400, F.A.C. or in 40 CFR 60 52.21(m).

   Please identify or evaluate locations near the proposed facility for a fully equipped ambient air monitoring station.

10. Compare the emission rates for the proposed project those proposed for the 1500 megawatt Sithe Desert Rock Energy Facility. Provide comparisons on same averaging times, e.g. 24-hour SO_2 and 24-hour NO_X. This can be done in terms of pounds per megawatt-hr (lb/MWH) to take advantage of the high efficiency characteristics of the Glades Project. The permit is available at:

    www.epa.gov/region09/air/permit/desertrock/desert-rock-proposed-permit.pdf

[Rule 62-212.400, F.A.C. (BACT)]

11. Review the possibilities of lower carbon monoxide (CO), hydrogen fluoride (HF) and sulfuric acid mist (SAM) emissions. For example review CO requirements for the Desert Rock project as well as the Seminole Electric Unit 3 project. The planned use of the wet scrubber and wet electrostatic precipitator (WESP) should greatly decrease HF and SAM emissions. [62-212.400, F.A.C. (BACT]

12. Evaluate the possibility of lower PM_{10} emissions based on the additional ESP under consideration for installation prior to the sorbent injection/fabric filter equipment. Also provide a set of PM, PM_{10} and $PM_{2.5}$ limitations based on filterable and condensable fractions. Compare to the extent possible with the values for the Desert Rock project.

13. Review the possibility of particulate continuous emissions monitoring systems (PM-CEMS).

14. Provide estimates of ammonia (NH_3) emissions and strategies to minimize slip and fine particulate formation potential. What kind of ammonia is proposed to be used (aqueous or anhydrous)? What safety measures will be in place for the transportation and storage?

15. Provide information comparing the Hg emissions from the proposed project with stationary source information from other emitters of Hg in South Florida. Estimate the relative contribution and increase of the proposed project to the total Hg emissions from substantial stationary sources of Hg such as waste to energy plants, other power plants, etc.

16. Indicate measures that will be taken to insure that Hg removed by the various air pollution control processes and discharged via the coal combustion by-products, scrubber effluents, etc. does not reenter the environment.

17. Please provide more information regarding air emissions during the construction phase of the proposed project, including number and types of vehicles, description of heavy equipment, etc. Describe the measures to minimize the effects of construction activities at the site.

18. Is there a plan to minimize construction and transportation equipment emissions by using ultra low-sulfur diesel fuel and minimizing idling?

19. Please provide more information regarding the types of vehicles and equipment used during operation of the proposed facility. Will there be a commitment to minimizing pollution by reducing idling and utilizing the use of ultra low sulfur fuel? Further, provide a detailed assessment of all traffic, including vehicle used, purpose of vehicle and miles traveled.

20. Describe the purpose and duration and emission characteristics of the batch plant shown in Figure 2-1 of the application.

21. Please expand the narrative description of the process, the coal handling system, limestone and reagent preparation system, and the fly and bottom ash handling system (include each emissions point).

22. What activities are contemplated for the train/engine repair location? Are there any emissions associated with this activity?

23. The application listed petroleum coke and U.S. and imported bituminous coal. It states (page 2-1) that the units will co-fire up to 20 percent by weight petroleum coke with coals and that

the amounts of each type will vary depending of economic conditions. What combination of fuels was used to calculate emissions? What is the worst case scenario?

24. Please identify the likely sources of the various fuels (coal and petcoke) mentioned in the application.

25. The BACT proposal for NO_X is stated as Advanced Combustion Technology (ACT) and SCR. Is the ACT a combination of low NO_X burners, overfire air or reburn or any other technology? Please explain.

26. Provide the protocol for the start up and shutdown to minimize emissions and quantify emissions during this period.

27. Provide estimates of and any considerations given to carbon dioxide emissions. Advise of any studies or pilot demonstrations projects in which FPL participates or plans to participate.

28. Please evaluate and provide information regarding the feasibility of dry cooling techniques versus mechanical draft cooling towers with drift eliminators.

29. Please total up the hazardous air pollutants (HAPs) estimated for the project.

30. What are the distances between the proposed project and the following geographical features and municipalities: the City of Moore Haven; Clewiston; Lake Okeechobee; Brighton Seminole Reservation; Everglades National Park; and Big Cypress National Preserve? Show these relationships on a map.

31. In general, the results of the ambient air quality analyses should be displayed in more reader-friendly graphical formats on maps that include geographic features and municipalities to allow a better appreciation of the degree to which they are affected by the proposed project. This will make the subject matter more readily understandable to all readers including experts and laymen.

32. Section 6.5 of the PSD Report states that the land use data of the Ft. Myers National Weather Service station was compared to the land use of the proposed project site. It also states that this comparison found that land use values were similar between the Ft. Myers station and the project site. Please provide these data to the Department for verification purposes.

33. The proposed project is PSD for VOC and NO_X, which are precursors to the pollutant ozone. In the PSD Report, impacts from the proposed project with regards to ozone are solely evaluated with respect to vegetation, specifically in the Class I areas. VOC emissions in excess of 100 TPY require an ambient air quality analysis for ozone. Please submit an ambient air quality analysis for ozone.

34. The proposed project triggers PSD for Total Fluorides. There are modeled concentrations for HF impacts listed in Table 6-7 of the PSD Report. Please provide additional information regarding the impact of Total Fluorides. For example, how would a 24-hour concentration of 0.028 micrograms per cubic meter impact the surrounding Class II area?

35. Table 6-7 in the PSD Report shows the emission rates used in the modeling analyses for the proposed project. The long term emission rates are equal to the short term emission rates. The modeling analyses should reflect the worst case scenario. Please model all short term

impacts using short term emission rates (i.e. the highest 24-hour emission rate, not 30 day average, for the 24-hour averaging period) for the Class I and Class II areas. Please submit all new modeling to the Department, including a Preconstruction Monitoring Analysis, a Significant Impact and Increment Analysis for all short-term averaging periods.

36. The CALPUFF modeling system was used to model impacts from the proposed project for the Class I areas. However, there are various versions of the model. The VISTAS version was used in the analysis for the Glades Power Park. While this version is accepted for use by the National Park Service, the EPA requires the use of the "regulatory" version (available on the EPA web site) to model the Class I Significant Impact Analysis and Increment, if required. Please model using the preferred EPA version or submit necessary documentation to obtain approval for using the VISTAS version.

37. Are the Results in Table 7-6 of the PSD Report for Method 6 results of modeling with the Initial or New IMPROVE equation?

38. The PM modeling including fugitive emissions has stack diameter inputs of 42 feet while Table 2-3 in the PSD Report states that the diameter will be 30 feet. Please correct the modeling or the Table to reflect the correct diameter. The modeled diameter of the cooling tower cells and emission rates do not correspond with Table 2-4 as well.

39. The PM modeling including fugitive emissions shows an Emission Factor for Wind Speed Emission Rate Variation of 1 for higher wind speeds for source ID AREA9WE, AREA2WE and BYPRODWE. Please explain.

40. Please explain how the Initial Vertical Dimension was determined for the volume sources.

41. Please provide further information regarding Railcar emissions. For example, emission source ID EP-45 includes railcar unloading, TP-3, according to Table A-2. However, Table A-3 shows railcar loading as TP-1, which is not a part of any emission points listed in Table A-2. Further, please explain which source ID's in the modeling analysis includes emissions listed in Table A-3.

42. Please provide further information regarding the truck/bulldozer traffic emissions. Please provide the truck traffic source ID's used in the modeling analysis.

43. Table A-4 in the PSD Report lists 2 inactive coal piles, F-14 and F-13. However, Table A-9 (page 1 of 3), states that F-14 is an active coal pile and Table A-9 (page 2 of 3) only has one inactive pile, F-13. Please clarify and note which Source ID is used in the modeling for these emissions.

44. Table A-4 in the PSD Report includes all emissions for all bulldozers and front end loaders listed in Table A-10 except for Bottom Ash Handling F-76. Was F-76 accounted for in the material handling operation emissions?

45. Table 6-6 in the PSD Report lists the building dimensions used in the modeling analysis. The modeling shows 19 of the 22 listed in the table. The 3 missing are the Railcar Area, the Limestone Track Hopper and the second Coal Transfer House. Please add these buildings to the modeling analysis. Should the Administration, Warehouse and Maintenance buildings be added to the modeling analysis?

46. The receptor grids for the SO_2 and PM_{10} Increment analyses have 450-500 receptors. The PM_{10} analysis only has receptors along the fence-line. Please verify that receptors are placed in "areas," not just "points" of "significance."

47. Where in the stack will CEMS be placed? Where will stack sampling platforms be located?

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please advise the professional engineer to make sure he/she uses the correct seal in compliance with the applicable requirements of the Florida Board of Professional Engineers.

If there are any questions, please call me at 850-921-9523 or Debbie Nelson at 850/921-9537.

Sincerely,

Alvaro A. Linero, Program Administrator
Bureau of Air Regulation
South Permitting Section

AAL/al

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COMMENTS AND RESPONSES

FDEP-1. Refer to the attached letter from the Federal Land Manager (Superintendent, Everglades and Dry Tortugas National Parks). The Department requires the same information as detailed therein. Also please document the contacts and consultations to-date about this project with the Vero Beach office of the U.S. Fish and Wildlife Service related to endangered species on site and in the environs of the proposed site.

RESPONSE: Responses to the questions and comments from the Federal Land Manager regarding the Air Construction/PSD Permit application (Appendix 10.1.5 of the SCA) are provided in Attachment FDEP-1.

The U.S. Fish and Wildlife Service has been contacted by FPL staff and staff from our environmental consultant Golder Associates multiple times to discuss the project and the threatened and endangered species on the site and the vicinity. These consultations were as follows:

- September 13, 2006: Letter to John Kelso providing description of site and requesting review.
- October 25, 2006: Meeting in Vero Beach; Contact: John Wrublik.
- December 5, 2006: Meeting in Vero Beach; Contact: Allen Webb.
- January 8, 2007: Meeting in Everglades National Park; Contact: John Wrublik (by phone).
- January 24, 2007: Meeting in Vero Beach; Contacts: Paul Sousa, Allen Webb, John Wrublik, Mark Musaus, Mark Barrett and Bill Miller.

FPL will continue to have active dialog with the USFWS as the project moves forward.

FDEP-2. General Electric and Conoco Phillips have described bituminous coal reference plants for Integrated Gasification and Combined Cycle (IGCC) units characterized by very low emissions. For example, the claimed emission values are 0.01 pounds per million Btu of heat input (lb/MMBtu) for sulfur dioxide (SO_2) and 0.02 lb/MMBtu for nitrogen oxides (NO_x). The assumptions for these cases are deep sulfur removal and selective catalytic reduction (SCR) to control emissions of SO_2 and NO_x. The provider's descriptions are available at:
www.gasification.org/Docs/2005_Papers/29KEEL.pdf and
www.ieacoal.org.uk/publishor/system/component_view.asp?LogDocId=81264&PhyDocId=5653

Please provide documentation of FPL's review of IGCC.
[Rule 62-210.200, F.A.C. (Definitions-BACT); Rule 62-212.400, F.A.C. (PSD and BACT)]

RESPONSE: FPL has provided the FDEP with a comprehensive evaluation of BACT available to control emissions for FGPP in the PSD application. FPL underwent an extensive technology design selection process and selected the proposed ultra-supercritical pulverized coal-fired ("PC") unit as the engineering design. EPA guidance indicates an IGCC analysis need not be viewed as part of the BACT process for a PC plant, as IGCC would redefine the FGPP source design (see Attachment FDEP-2A). Regardless, FPL did undertake a review of alternative design technologies, including IGCC technology. A study produced on behalf of FPL found that IGCC as applied to FGPP is not appropriate or preferable for the 1,960-MW power plant at FGPP (see Attachment FDEP-2B). In summary, the study found that the PC unit as proposed by FGPP is the preferred technology for the Glades site based on environmental emissions, reliability, economics, and commercial availability.

Regarding the reference to the General Electric and Conoco Phillips reference plants in the question, these reference plants have not been demonstrated in practice for their claims of low emission rates. Recent IGCC projects using these reference plant technologies have not been permitted. Those projects being proposed do not have proposed emission rates at the low levels indicated by the reference plants. For example, AEP proposed emission rates for the Mountaineer IGCC facility in West Virginia, September 29, 2006, and Excelsior Energy for Mesaba Energy facility in Minnesota, June 16, 2006, were higher than the reference plants described in the question as shown below.

Emissions in lb/MMBtu at steady state conditions (without startup and shutdown cycles emissions)	NO_x	SO_2
AEP Mountaineer IGCC, West Virginia (3) (based on GE reference plant)	0.057	0.017
Mesaba Energy IGCC, Minnesota (4) (based on Conoco Phillips referente plant)	0.057	0.03
FGPP USCPC, Florida	0.05	0.04

References:

1. www.gasification.org/Docs/2005_Papers/29KEEL.pdf Comparative IGCC Performance and Cost for Domestic Coals presented by Conoco Phillips at the Gasification Technologies Council, on October 11, 2005 in San Francisco, California.
2. www.ieacoal.org.uk/publishor/system/component_view.asp?LogDocId=81264&PhyDocId=5653. Delivering the Benefits of IGCC presented by GE Energy at the 2nd International Conference on Clean Coal Technologies for our future on May 10, 2005 in Sardina, Italy
3. AEP Mountaineer IGCC Project, Permit to Construct Application, September 29, 2006.
4. MPUC Joint Application, The Mesaba Project, June 16, 2006.
5. Clean Coal Technology Selection Study Final Report, January 2007.

FDEP-3. Are there future phases planned for the facility?

RESPONSE: There are no current plans to add future phases to the FPL Glades Power Park.

FDEP-4. Very little information is provided regarding the characteristics of the air pollution control equipment in terms of vessel sizes, reagent use estimates, air to cloth ratios, electrostatic precipitator capacities (ESP fields), etc. Please update the information in the application with the most recent information available to FPL based on the present status of front end engineering design (FEED). [Rule 62-210.070, F.A.C. (Standards for Issuing or Denying Permits)]

RESPONSE: FPL is in negotiations with potential equipment vendors regarding the final design of the air pollution control systems. The information provided by the vendors has been summarized below as the conceptual design of the air pollution control systems. The conceptual design provided will be supported by guarantees of the emissions rates provided in the PSD/Air Construction Application.

Selective Catalytic Reduction (SCR): The SCR will be furnished by the boiler supplier and integrated within the boiler system. It will be placed after the economizer and prior to the air heater. Conceptual information is presented below:

- SO_2 to SO_3 Conversion: 2 percent including combustion
- Catalyst Type: High Dust, homogeneous grid honeycomb
- Catalyst Configuration: Vertical flow fixed bed
- Number of Reactors Per Unit: 2
- Number of Initial Catalyst Layers (Per Reactor): 3
- Number of Spare Layers (Per Reactor): 1
- Catalyst Layer Depth (Per Layer): 4.4 feet (ft)
- Reactor Dimensions (Inside x Inside): approx. 45 ft x 50 ft
- Full Load Gas Flow: 4,500,000 acfm at 650°F
- Superficial Velocity Through Catalyst: approx, 17 ft/sec
- SCR Pressure Drop Through Box and Ductwork: 3 inches (w.c.)
- Ammonia Consumption @ Design Conditions: approx. 1,130 lb/hr

Fabric Filter: The fabric filter will be furnished by the air pollution control system (AQCS) vendor. It will be a pulsed jet fabric filter system. Dust laden gas from the boiler exit is drawn into the inlet plenum of the baghouse by an induced draft fan. The inlet plenum spans the length of the baghouse and ducts the gases through butterfly type dampers into the hopper of each compartment. The gases are directed upward by vanes and baffles through the bags and tube sheet onto the "clean side" of each filter bag. Cleaned gases from the filter bags of each compartment are drawn upward through a poppet damper into the outlet plenum, which is common to all compartments. Gases in the outlet plenum are discharged into the outlet ductwork. Dust collected on the outside surface of the filter bags is periodically removed by the pulse jet cleaning system. One row of bags is cleaned with each pulse. The system will use a low volume, high pressure pulse of air to introduce a shock wave onto the bags. The shock wave causes an intentional, local deformation of each bag manifested as an instantaneous increase in diameter. As this wave propagates down length of bag, elastic forces pull the bag back to the cage, while the momentum of the dust causes it to dislodge from fabric. The dust falls into the hopper where it is removed by the ash handling system. The cleaning operation is automatically sequenced through the compartments, and is initiated by a differential pressure signal, an adjustable time cycle, or manually. The cleaning process is completed in approximately five to six minutes per half compartment. The following are the conceptual design features of the fabric filter system (or equivalent):

- Air-to-Cloth Ratio: 4 to 1 (or less)
- Baghouses per Unit: 2
- Baghouse Dimensions (including ash hoppers): 63 ft high, 87 ft wide, 126 ft long
- Baghouse design: 10 compartments per baghouse, containing 1440 bags, 26 ft long x 5 inches diameter (nominal)
- Bag material: PPS Rytonc (polyphenylene sulfide), 18 ounces per square yard, 8-year life
- Pressure Drop: 7 inches (wg)

- Compartments: 10 individual compartments with walk in plenum to allow on-line maintenance. 72 pneumatically activated double diaphragm valves per component
- Controls: PLC
- Instrumentation: Thermocouples, compartment differential pressure, baghouse differential pressure, baghouse pulse pressure regulators.
- Ash Hoppers: 2 per compartment, 2 heaters per hopper, electromagnetic vibrators with strike plates.

Flue Gas Desulfurization (FGD) System: The wet FGD system will consist of three subsystems: Reagent Preparation, Absorber Island, and Gypsum Dewatering. The Reagent Preparation system will consist of a horizontal wet ball mill (closed-circuit grinding system) with associated day silos and reagent slurry feed tank with associated pumps. The grinding system will be sized to produce a 28- to 30-percent solids slurry of limestone with a grind of 95-percent -325 mesh. The slurry medium for the limestone is reclaim water (filtrate) from the gypsum dewatering system. The Absorber Island consists of a single grade-mounted countercurrent open spray tower absorber. The absorber will use a solid Alloy C-276 inlet (or equivalent) that is continuously washed with fresh water to ensure that no buildup of solids occur at the wet-dry interface. All gas/liquid contact will be provided by internal spray headers, with a spare spray level. Above the spray headers is a high-efficiency two-stage vertical flow mist eliminator system. Oxidation will be accomplished by side-entering agitators with lance type spargers. Oxidation air blowers will provide the oxidation air with one blower as spare. The oxidation air blowers are sized to deliver air at a stoichiometry that ensures oxidation rates in excess of 99 percent. The Gypsum Dewatering system will consist of horizontal belt vacuum filters with associated auxiliaries; with one filter system as a standby spare. Each filter is sized to dewater the byproduct gypsum slurry on a continuous (24-hour) basis. The following are the conceptual design information for the FGD systems:

- Absorbent: Limestone >94 percent available $CaCO_3$.
- Absorber: One per unit, countercurrent open spray tower, 6 percent moly , 70-ft diameter and 150 ft high, 5 spray stages plus 1 spare with 5-ft width between stages, 1,452 cone type, spray nozzles per absorber, 62,500 gpm per spray level .

Mist Eliminator System: Vertical flow, polypropylene or FRP (Chevron type, Munters DV210+ or equivalent).

Wet Electrostatic Precipitator (WESP): The WESP will be a horizontal-flow plate type design with the following conceptual design components:

- Design: Six chambers per WESP, 48 gas passages per chamber.
- Fields: 3
- Electric Fields: Six per chamber
- Collection Area: 352,000 ft^2
- Specific Collection Area: 90+ ft^2/acfm
- Gas velocity: 7.5 ft/sec
- Residence Time: 3.6 sec
- Discharge Electrode: 1.5-inch diameter, 16-gauge alloy
- Collection Electrode: 9 ft wide x 40 ft tall, minimum 16-gauge alloy
- Electrical: Six high-voltage transformer-rectifier sets
- Operating Current Density: 0.059 mA/ft^2 of plate area

- Control: PLC

FDEP-5. Please update the status of the mercury (Hg) control equipment design. Advise whether FPL will actually install another electrostatic precipitator (ESP) in front of the sorbent injection equipment and fabric filter. [Rule 62-070, F.A.C.]

RESPONSE: The current design for mercury control does not include an ESP but does include a fabric filter. In addition, sorbent injection will be added as part of the air quality control system (AQCS) to enhance mercury removal. FPL's plan is to inject Powdered Activated Carbon (PAC) into the ductwork between the air heater outlet and the fabric filter inlet. PAC acts in two ways: by adsorbing mercury directly and by catalytically oxidizing additional elemental mercury. The carbon with adsorbed mercury is collected as a particulate in the fabric filter and the oxidized mercury is scrubbed out in the wet FGD system. In addition to PAC injection, hydrated lime (or equivalent) will be injected after the air heater. Use of hydrated lime enhances the effectiveness of PAC injection and also protects the duct work and fabric filter from potential acid condensation.

FDEP-6. Clarify the thermal cycle efficiency of the units given their designation as ultracritical pulverized coal units. The literature typically describes such technologies as capable of yielding efficiencies greater than 40 percent (%). Describe the basis for the efficiency estimate (e.g. net, higher heating value, semi-tropical conditions, etc.).

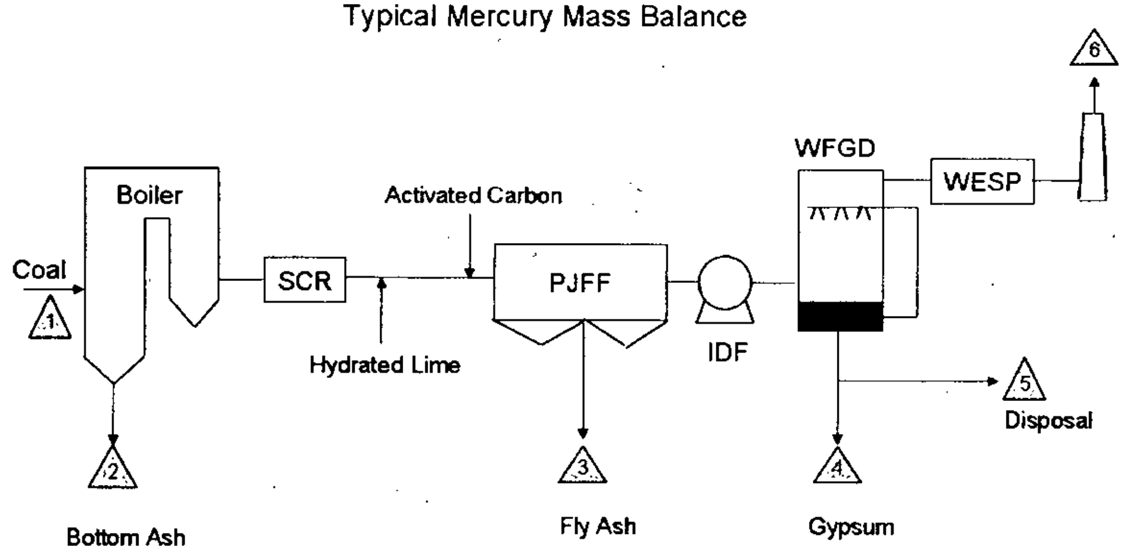
RESPONSE: The gross thermal efficiency for FGPP reflecting the efficiency of the steam generator is 41.5 percent based on a maximum heat input of 8,700 MMBtu/hr and a gross generation of 1,060 MW (gross heat rate of 8,208 Btu/kW-hr). These parameters were included in Air Permit/PSD Application and based on the long term long-term operation of FGPP. The "new and clean" heat rate will be better than that indicated above.

The term ultra-supercritical for the boiler design selected for FGPP was based on the U.S. Department of Energy (DOE) definition of "ultra-supercritical steam cycle". The operating for the FGPP boilers will exceed 3,600 pounds per square inch (psi) and the main superheat steam temperatures will be 1,100°F. The DOE periodical titled "Clean Coal Today" on page 6 states: "Steam cycles with operating temperatures exceeding 3,600 pounds per square inch (psi) and steam superheat temperatures approaching 1,100°F are considered 'ultra-supercritical' (USC)." A copy of this periodical is attached.

FDEP-7. Include a mass balance calculation including a simplified process flow diagram depicting the approximate average Hg flows in and out of the process steps. The flows should include: Hg in the incoming fuel; the amount exiting via the ESP fly ash; the amount captured by sorbent injection and fabric filtration; the amount removed by the wet scrubber; and the amount exiting the stacks. Also describe any discharges via scrubber effluent to treatment or disposal.

RESPONSE: The mass balance depicting approximate average mercury flows is shown in the drawing that follows.

Typical Mercury Mass Balance



SCR = Selective Catalytic Converter
A/H = Air Heater
PJFF = Pulsed Jet Fabric Filter
IDF= Induced Draft Fan
WFGD = Wet Flue Gas Desulfurization
WESP = Wet Electrostatic Precipitator

	Annual Average Mercury					
	1 Coal	**2 Bottom Ash**	**3 Fly Ash**	**4 Gypsum**	**5 Disposal (UIC)**	**6 Stack**
Mercury, lb/MWh	$99X10^{-6}$	0	$79.2X10^{-6}$	$4.95X10^{-6}$	$4.95X10^{-6}$	$9.9X10^{-6}$
Mercury, lb/year	1830	0	1464	182.1	0.915	183
Mercury, ppm	0.15	0	1.8	0.128	0.0005	0.001

Mercury enters the boiler through the fuel being fed to the boiler. The mercury enters as elemental mercury with a very small portion entering as particulate mercury. During combustion the elemental mercury is released in the flue gas as a vapor. The particulate mercury is released as very small particulates. Samples of bottom ash and economizer ash from several pulverized coal boilers were analyzed for mercury. Mercury was not found in the samples. Therefore, it is assumed that bottom and economizer ash will not contain mercury. Consequently, all of the mercury is carried out with the flue gas and exits the boiler through the air heater. Immediately downstream of the air heater powdered activated carbon (PAC) is injected to adsorb and capture most of the vaporized mercury. It is anticipated that 70 to 90 percent of the mercury will be captured in the fabric filter and exit with the fly ash.

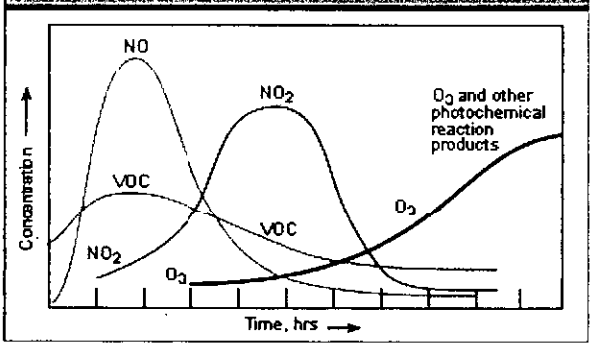
Installed downstream of the fabric filter is a wet flue gas desulfurization (FGD) system to remove SO_2 contained in the flue gas. Testing has shown mercury removal in WFGD systems varies from 30 to 90 percent. It is assumed that 50 percent of the remaining mercury will be removed in the wet FGD system with 99.5 percent of mercury partitioning to the gypsum and 0.5 percent to the scrubber effluent and waste water disposal.

Downstream of the wet FGD system a wet electrostatic precipitator (WESP) is installed to remove fine particulates. Some pilot testing has been conducted that shows a minimal amount of mercury will be removed in the WESP. However, to be conservative, it is assumed that no mercury will be removed in the WESP.

FDEP-8. According to the application, emissions of volatile organic compounds (VOC) are estimated to be 260 tons per year (TPY). Estimated emissions of NO_X are approximately 3,800 TPY. Please provide conduct an ambient impact analysis for ozone including the gathering of ambient air quality data. [Rule 62-212(2)(e)1.e., F.A.C.; 40 CFR 52.21(i)(5)(i) (footnote 1) (July 1]

RESPONSE: Volatile organic compounds (VOCs) and NO_x emissions are precursors to the formation of ozone (O_3). O_3, although not directly emitted as a result of FGPP, can be formed when NO_x and VOCs react in the atmosphere in the presence of sunlight. Natural (i.e., without man-made sources) ambient concentrations of O_3 are normally in the range of 20 to 39 $\mu g/m^3$ (0.01 to 0.02 ppm) (Heath, 1975). Nitric oxide (NO) is the primary NO_x that will be emitted from FGPP, but is also emitted by automobiles, trucks, and other fuel-burning emission sources. NO is rapidly converted to nitrogen dioxide (NO_2) due to photochemical reactions. The formation of NO_2 stimulates the O_3-forming reaction because NO_2 is efficient at absorbing sunlight in the ultraviolet portion of its spectrum. As the reactions proceed, NO_2 reacts to form particulate and vapor-phase nitrates. As the NO concentration drops, the levels of O_3 rise rapidly. Along with the increase in O_3, the levels of various partial oxidation products also increase. The general nature of the photochemical reactions is illustrated by the pollutant profiles (Figure 1) found in smog chamber studies that simulate urban air masses (EPA, 2007).

Figure 1. Pollutant Concentration Profiles Due to Photochemical Reactions



Source: EPA 2007

The photochemical reactions are complex and in determining impacts regional models must be used. There are no models in EPA's Guideline on Air Quality Models (Appendix W of 40 CFR Part 51) for assessing impacts of NO_x and VOC emissions from a single source. Models such as the Urban Airshed Model are used in urban areas that are typically non-attainment areas and require extensive ambient, emissions and meteorological data requiring years to develop. In these areas there are considerable sources of NO_x and VOC well over several hundreds of thousands of tons per year (TPY) with favorable meteorological conditions for photochemical reactions. For example, the Atlanta area, with both mobile and stationary sources, is an area where such modeling is performed.

In contrast, FGPP is located in Glades County that is very rural without many stationary sources of NO_x or VOCs. While there is no ambient air monitoring in Glades County, there are monitors located in adjacent Highlands County and in the coastal counties of Palm Beach and Lee. Data from the nearest monitor to FGPP that measures O_3 concentrations, located in Highlands County as well as monitors located in nearby Palm Beach and Lee Counties are presented in Table FDEP-8A (Attachment FDEP-8). These stations measure concentrations according to EPA procedures and show, based on the O_3 monitoring concentrations measured over the last several years, that the region is in attainment of the existing 1-hour O_3 AAQS as well as the new 8-hour O_3 AAQS. Indeed, the O_3 concentrations as compared to the AAQS are similar in all three locations.

The potential VOC and NO_x emissions from FGPP are 260 and 3,827 TPY, respectively. On a regional basis, the total VOC emissions in the region (i.e., Glades, Highlands, Hendry, Lee, Charlotte, Okeechobee, Martin, and Palm Beach Counties) were 128,509 TPY for stationary and mobile sources (based on AIRSdata website by EPA for 2001, the latest year of available data). The maximum VOC emissions increase due to FGPP is 260 TPY, which represents less than a 0.3-percent increase in regional VOC emissions. Similarly, the regional emissions of NO_x, were 104,364 TPY and FGPP would be less than 5 percent of the total. Southern Florida also is dominated by trade winds during the O_3 formation months typically minimizing conditions where O_3 can be readily formed.

In addition, the maximum concentrations of NO_2 are predicted to be very low and decrease considerably with distance. Even if the NO_x is converted directly to O_3, it would result in low concentrations compared to the O_3 standard. Table FDEP-8B illustrates the maximum 8-hour NO_2 concentrations for downwind distances from 1 to 15 kilometers. As shown in this illustrative example, the NO_2 concentrations decrease rapidly and, if converted to O_3, the concentrations are a very small percentage of the O_3 AAQS.

Taking together the existing air quality status, the relatively small regional contribution of VOC and NO_x from FGPP, regional meteorological conditions, and the low predicted concentrations of ozone precursors from FGPP, FGPP will not cause or contribute to an exceedance of the AAQS for O_3.

FDEP-9. The maximum ambient concentrations predicted at ground level in Table 6-7 are all based on a single emission rate per pollutant irrespective of applicable averaging times. This analysis should be redone using the maximum emission values that will occur during the specified averaging times (i.e. 3-hour, 24-hour, annual, etc. as applicable). The information provided is insufficient to conclude that ambient monitoring is not required for the pollutants and related averaging times given in Rule 62-212.400, F.A.C. or in 40 CFR 60 52.21(m).

Please identify or evaluate locations near the proposed facility for a fully equipped ambient air monitoring station.

RESPONSE: The maximum predicted concentrations consistent with the monitoring exemption in Rule 62-212.400(4)(e), F.A.C., have not changed from those presented in Tables 3-4 and 6-7 in the Air Construction/PSD Permit Application. The only air pollutant to exceed the thresholds in Rule 62-212.400(4)(e), F.A.C., is VOC, which is the surrogate pollutant for O_3. Ambient air quality data for O_3 was provided in Section 5.1, Table 5-1, of the Air Construction/PSD Permit Application. The closest O_3 monitoring is in a location similar to Glades County (i.e., center of the southern Florida peninsula) and is more heavily developed. Highlands County has a population of about 100,000 in contrast to the 11,000 in Glades. The response to FDEP-8 presented additional regional O_3 data to supplement the Air Construction/PSD Permit Application.

Although additional air quality monitoring is not required for the purposes of application completeness, based on discussions with the FDEP, FPL is evaluating potential locations for an ambient air quality monitoring station near the proposed facility.

FDEP-10. Compare the emission rates for the proposed project and those proposed for the 1,500 megawatt Desert Rock Energy Facility. Provide comparisons on same averaging times, e.g. 24-hour SO_2 and 24-hour NO_X. This can be done in terms of pounds per megawatt-hr (lb/MWH) to take advantage of the high efficiency characteristics of the Glades Project. The permit is available at:
www.epa.gov/region09/air/permit/desertrock/desert-rock-proposed-permit.pdf
[Rule 62-212.400, F.A.C. (BACT)]

RESPONSE: Table 10-1 presents a comparison of the performance and emissions proposed for FGPP and those in the conditions proposed by EPA Region 9 for the Desert Rock Energy Facility. The averaging times have been noted in the table. As described in the response to FDEP-1, FPL is proposing a 24-hour block mass SO_2 emission limit for both units equivalent to 0.04 lb/MMBtu. FPL is also proposing a 3-hour block mass SO_2 emission limit for both units equivalent to 0.065 lb/MMBtu. In contrast, the mass SO_2 emission limit for Desert Rock is equivalent to 0.09 lb/MMBtu. For SO_2 and NO_x, Desert Rock does not have 30-day rolling averages but has a 365-day rolling average mass emission limit equivalent to 0.0556 lb/MMBtu.

As noted from the table the proposed emission rates from FGPP for SO_2, NO_x, and fluorides are less than those proposed by EPA for Desert Rock. The emissions of SAM from both projects are the same in lb/MMBtu. However, as shown in the table, the performance of FGPP as shown by the gross and net heat rates is more than 10 percent better than Desert Rock. This is shown by lower emissions on an energy output basis, which is becoming more common as New Source Performance Standards (NSPS) for electric utility units. While the FGPP CO and PM/PM_{10} emission rates are slightly higher than Desert Rock on a lb/MMBtu basis; on a lb/MW-hr basis, the emission rates are similar.

For mercury, a specific emission limit was not established in the proposed PSD permit conditions for Desert Rock since under EPA rules mercury is not a PSD pollutant. The mercury emission limit for Desert Rock is the default value in the NSPS Subpart Da as noted in the EPA proposed conditions. The mercury emissions from FGPP are substantially less than those in the NSPS.

FDEP-11. Review the possibilities of lower carbon monoxide (CO), hydrogen fluoride (HF) and sulfuric acid mist (SAM) emissions. For example review CO requirements for the Desert Rock project as well as the Seminole Electric Unit 3 project. The planned use of the wet scrubber and wet electrostatic precipitator (WESP) should greatly decrease HF and SAM emissions. [62-212.400, F.A.C. (BACT]

RESPONSE: FPL is proposing a CO emission limit of 0.13 lb/MMBtu when firing coal as an initial stack test and a 30-day rolling average CO emission limit of 0.15 lb/MMBtu using CEMs. This emission limit is equivalent to that proposed by FDEP for Seminole Electric Cooperative Inc.'s, Seminole Generating Station (SGS) Unit 3. FGPP and SGS Unit 3 are similar type units and will both utilize eastern U.S. bituminous coals with co-firing of petroleum coke. As shown in the BACT analysis for CO in Section 4.2.6 of the Air Construction/PSD Application, combustion controls reflect the technology that would provide the maximum degree of emission reduction for limiting CO emissions when taking into account the energy, environmental and economic impacts and other costs, and is available. Add-on technology, such as thermal oxidation, has not been used on pulverized coal fired units and its application is not technically or economically practicable. The Department confirmed these conclusions in the Technical Evaluation and Preliminary Determination for SGS Unit 3, which established an emission limit of 0.13 lb/MMBtu for 100 percent coal firing and 0.15 lb/MMBtu on a 30-day rolling average basis. It should also be noted that the high efficiency for FGPP reduces the amount of CO generated per unit of output. As noted in FDEP-10, FGPP will be

10 percent more efficient that Desert Rock, which will not co-fire petroleum coke with coal. Also please note that the maximum CO impacts of FGPP are more than 12 times lower than the Significant Impact Levels (Table 6-8 in the Air Construction/PSD Application).

FGPP, similar to Seminole Unit 3, is planning to utilize a range of fuels, including petroleum coke. Fuels with different characteristics such as gridability and volatile matter can influence combustion and resultant CO emissions. The Desert Rock Energy Facility is planning to use a single coal source from the BHP Billiton New Mexico Coal mine located in the Navajo Nation. The Desert Rock Energy facility is located within the Navajo Nation. With a single source, the coal characteristics would not be as variable as it would be if using a range of coals and petroleum coke. As a result, the proposed BACT for FGPP of 0.13 lb/MMBtu on a single stack test when using coal and 0.015 lb/MMBtu on a 30-day rolling average is consistent with the case-by-case requirements of BACT.

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For fluorides (as HF), the emission rate proposed as BACT was based on an evaluation of the fluoride content in the coals proposed for FGPP with substantial reduction in emissions (97 percent) with the AQCS proposed. The proposed emission rate is lower than that established by EPA Region 9 for the Desert Rock Energy Center and equivalent to that proposed by the Department for SGS Unit 3. Indeed, on an output basis, the emission rate is lower than both the Desert Rock and SGS3 projects. As shown in Table B-7, Appendix B of the Air Construction/PSD Application, an emission rate of 0.00023 reflects one of the lowest rates proposed or determined to be BACT. Indeed, this emission rate reflects the lower ¼ of all established limits (25 percentile). This emission rate also reflects the uncertainty in testing at such low concentrations. As noted in Table 4-1 of the Air Construction/PSD Application, EPA has reported precision and accuracy difficulties measuring fluorides at concentrations less than 5 ppm. The proposed emission limit is equivalent to 0.3 ppm.

The emission limit proposed as BACT for SAM reflects the lowest rate for projects that are using moderate sulfur fuels as shown in Table B-5 in Appendix B of the Air Construction/PSD Application. The only facility with a much lower SAM emission rate (Southwest-Springfield, Missouri) is using power river basin coal with significantly lower sulfur content. Also, co-firing petroleum coke can slightly increase the oxidation rate of SO_2 to SO_3 requiring greater amount of control to limit SAM. As discussed in FDEP-4, the conceptual design of the AQCS includes hydrated lime injection, which has the collateral benefit of reducing SO_3 and consequently SAM. Please note that as shown in Table FDEP-10, the SAM emissions for FGPP will be more than 10 percent lower than the Desert Rock Energy Center.

FDEP-12. Evaluate the possibility of lower PM_{10} emissions based on the additional ESP under consideration for installation prior to the sorbent injection/fabric filter equipment. Also provide a set of PM, PM_{10} and $PM_{2.5}$ limitations based on filterable and condensable fractions. Compare to the extent possible with the values for the Desert Rock project.

RESPONSE: The current design for mercury control does not include an ESP prior to the sorbent injection system and fabric filter. The PM and PM_{10} emission limit for filterable material from FGPP is proposed as 0.013 lb/MMBtu on a 3-hour test basis. FGPP is also proposing a sulfuric acid mist (SAM) emission limit of 0.004 lb/MMBtu also as a 3-hour test basis. These proposed emission limits are the same as those proposed by FDEP for the Seminole Unit 3 Project in 2006.

An emission limit for filterable $PM_{2.5}$ is not appropriate since there are no approved emission test methods for the measurement of $PM_{2.5}$ and the vast majority of PM in the environment is due to emissions of SO_2 and NO_x, which will be controlled and continuously measured from FGPP. The primary condensable emission from coal-firing will be SAM, which will be controlled using wet-electrostatic precipitators. A separate total PM/PM_{10} emission limit is not considered necessary since both filterable and primary condensable will be determined.

The proposed PSD approval for the Desert Rock Energy Center included a filterable PM emission limit of 0.010 lb/MMBtu over a 24-hour period using EPA Method 5I and a total PM_{10} emission limit of 0.020 lb/MMBtu averaged over a 24-hour period. The proposed emission limits for FGPP are as stringent as that proposed for Desert Rock Energy Center when the averaging time is considered. FGPP proposes a 3-hour test while a 24-hour average is proposed for the Desert Rock Energy Facility. In addition, as discussed in the response to FDEP-11, the Desert Rock Energy Center will utilize a single source of fuel unlike that for FGPP.

FDEP-13. Review the possibility of particulate continuous emissions monitoring systems (PM-CEMS).

RESPONSE: The only reliable means to determine particulate matter (PM) emissions from a stationary source is to use one of the manual stack testing methods such as EPA Methods 5, 5i, or 17 or ASTM D 3685-98. Several field evaluation studies are underway using instruments to continuously monitor PM emissions from coal-fired steam generating units. EPA recently reviewed and revised the New Source Performance Standards for electric utility steam generating units (February 27, 2006; 71FR9866), and elected not to require continuous PM monitors for compliance measurements. Instead, EPA specified a Method 5 stack test as the performance test method.

There are commercially available instruments that advertise the ability to provide continuous measurement of PM emissions. However, unlike SO_2 and NO_X continuous monitors, commercially available continuous PM monitors do not provide a direct measure of particulate mass emissions. Direct measurement would accurately determine particulate mass in volume that was sampled, similar to CEMs for SO_2 and NO_x.

PM CEMS typically use one of five following basic principles of operation: (1) light scattering, (2) light absorption, (3) optical scintillation, (4) triboelectric effect, and (5) beta attenuation. The light scattering, light absorption and optical scintillation rely on the premise that PM concentration is related to optical or light-based phenomenon. The triboelectric effect is based on measuring the transfer of an electric charge when particles impact an in-stack sensor probe. Most of the commercially available PM CEMS operate within the stack. The exhaust stacks for FGPP will be saturated with moisture as a result of the wet FGD system, and such technologies cannot differentiate water droplets from particles. These devices are not appropriate for units utilizing a wet FGD system such as FGPP. In fact, most electric utility units using wet FGDs have opacity measurements after the particulate control device and prior to the FGD system.

Beta technology and one recently developed light scattering technology continuously extract samples for measurement. For FGPP, only extractive PM CEMS technologies would be appropriate given the wet nature of the exhaust. However, while NIST-traceable calibration gases are readily available for SO_2 and NO_x continuous monitors, there are no calibration materials exist for PM CEMS. Since neither the beta attenuation nor light scattering technologies measure mass directly, these extractive methods must be calibrated against some manual PM reference method measurement procedure like EPA Method 5, Method 5i or Method 17. This process requires repetitive testing that is both time consuming and expensive. Moreover, the characteristics of the emitted PM from pulverized coal-fired power plants can be variable over time due to fuel and combustion conditions. This variability in the particulate properties can translate into altering a PM CEM's calibration curve, thereby affecting the accuracy of the measurements.

For FGPP, particulate stack testing as provided for in EPA's NSPS in 40 CFR Part 60 Subpart Da is proposed. In addition, an opacity monitor will be installed after the fabric filter. It should be noted that upon operation a Compliance Assurance Monitoring (CAM) plan will be required. It is anticipated that this plan will include control parameters for both the fabric filter and the WESP as primary and secondary air pollution control devices. This plan would provide valid indicators, along with the opacity monitor to demonstrate that the PM emission limit established for FGPP would be met on a continuous basis.

FDEP-14. Provide estimates of ammonia (NH_3) emissions and strategies to minimize slip and fine particulate formation potential. What kind of ammonia is proposed to be used (aqueous or anhydrous)? What safety measures will be in place for the transportation and storage?

RESPONSE: Ammonia emissions will be minimal in the stack exhaust for FGPP. The only ammonia that will be present in the flue gas is the ammonia slip from the selective catalytic reduction (SCR) system installed to reduce NO_x emissions. Ammonia is injected into the flue gas prior to the flue gas passing over the SCR catalyst for NO_x conversion. The slip will be a maximum of 5 ppm at 6-percent O_2.

The SCR system is designed to minimize the ammonia slip. Design features include:

- Ammonia injection system designed to ensure proper contact between the ammonia and the flue gas
- Catalyst design to minimize the ammonia slip
- Catalyst seal design to minimize ammonia slip

A portion of the unreacted ammonia will combine with SO_3 to form particulate matter that would be collected in the fabric filter system. Non-reacted ammonia entering the wet FGD system will be absorbed in the limestone slurry since ammonia gas is extremely soluble in water. The actual ammonia slip exiting the stack is expected to be 10 percent or less of the ammonia slip entering the FGD system. Any remaining particulate will be collected in the wet electrostatic precipitator installed downstream of the wet FGD system, which will collect fine particulate from the flue gas prior to stack exit.

Both anhydrous and aqueous ammonia are being considered for the project. FPL will fully comply with EPA's regulation regarding Risk Management Plan/Process Safety Management (RMP/PSM). The equipment to transport, store or inject the ammonia will be designed to meet the strict codes applicable to the applications. Applicable codes and standards include but are not limited to: American Society of Mechanical Engineers (ASME) standards, USEPA Chemical Accident Prevention provisions (40 CFR Part 68), National Fire Protection Association (NFPA) standards, and Occupational Safety and Health Administration standards (OSHA, 29 CFR 1910) standards. The unloading facilities will be located to minimize conflict with plant traffic and plant equipment. Operators will be fully trained in the proper procedures for safely handling and unloading the ammonia. Safety and emergency response training will also be an integral part of the training.

FDEP-15. Provide information comparing the Hg emissions from the proposed project with stationary source information from other emitters of Hg in South Florida. Estimate the relative contribution and increase of the proposed project to the total Hg emissions from substantial stationary sources of Hg such as waste to energy plants, other power plants, etc.

RESPONSE:

Background

Mercury is emitted from natural sources as well as from anthropogenic sources. In addition, some of the mercury from both of these types of sources deposited to the Earth's surface is re-emitted to the atmosphere mostly as elemental mercury. Current global (both natural and anthropogenic) emissions of mercury are estimated to be between 4,840 and 7,700 tons per year (EPA, 2006). About half of world-wide anthropogenic emissions are estimated to originate from Asia.

Natural sources of mercury, such as volcanic eruptions and emissions from the ocean, have been estimated to contribute about a third of current worldwide mercury air emissions, whereas man-made emissions account for the remaining two-thirds. Much of the mercury circulating through today's environment is mercury that was released years ago, when mercury was commonly used in many industrial, commercial, and residential products and processes. Land and water surfaces can repeatedly re-emit mercury into the atmosphere after its initial release into the environment.

Emissions of mercury in the United States from man-made sources have fallen by more than 45 percent since passage of the 1990 CAA Amendments. Regulations that were issued in the 1990s to control mercury emissions from the burning of municipal solid waste require more than a 90 percent reduction in emissions from these facilities. In addition actions to limit the use of mercury, most notably Congressional action to limit the use of mercury in batteries and EPA regulatory limits on the use of mercury in paint, contributed to the reduction of mercury emissions from waste combustion during the 1990s by reducing the mercury content of waste. More recent regulation, including regulations to limit mercury emissions from chlorine production facilities that use mercury cells and regulation of industrial and utility boilers, will further reduce emissions of mercury.

As important as the amount, the type of mercury is important in considering emissions. Mercury is present in the atmosphere mostly as elemental mercury and as oxidized mercury species. The oxidized mercury species are also referred to as divalent mercury and can be present in the gas phase or in the particulate phase. When in the gas phase, divalent mercury is referred to as reactive gaseous mercury and includes mercury chloride, mercury hydroxide, and mercury oxide. Particulate mercury in the atmosphere could arise from divalent mercury bound to particulate matter, or primary particulate mercury. In the global atmosphere, elemental mercury accounts for more than 90 percent of total mercury on average.

Mercury Emissions in Florida and South Florida

The last complete emissions inventory conducted in Florida was performed for the year 1990 (KBN Engineering and Applied Sciences, Inc., 1993). The total anthropogenic mercury emissions in Florida were estimated to be 32,960 pounds in 1990. The major sources identified in this study included municipal solid waste (MSW) combustion (9,152 pounds), paint application (6,980 pounds), electric utility industry (6,706 pounds), electric apparatus (3,703 pounds) and medical waste incineration (3,406 pounds). As indicated above, considerable progress has been made since 1990 in implementing controls on sources and removing mercury from products. In addition, our knowledge of mercury emissions from many sources has been improved through continued research.

The previous inventory has not been updated to the extent that all atmospheric sources of mercury have been quantified as in the 1993 study. The reporting of mercury emissions is often not complete given the different regulatory requirements (Annual Operating Reports and Toxic Release Inventory) and methods for calculating are not consistent. As such, while an accurate inventory of mercury emissions in Florida cannot be completed for this response, this response reflects the latest information available.

The latest information on mercury emissions in Florida available from FDEP is presented in Attachment FDEP-15, Table FDEP-15a (state-wide). The total mercury emissions are identified as 1.3761 tons or 2,752 pounds. However, the emissions are not complete as many facilities, while having mercury emissions, are below the threshold for reporting and no information is provided. In addition, many of the sources identified in the 1993 study are not included and such emissions have not changed with the implementing of mercury reductions at sources and products. For example, mercury emissions from sugar cane processing (296 pounds) and open burning (404 pounds) are should also be included in the state-wide mercury inventory. In addition, recent mercury emissions estimates for certain industries have been developed that provide insight on total mercury emissions in Florida. The EPA has estimated that mercury emissions from coal-fired power plants in Florida were 1,923 pounds in 1999. Given that CAMR has not yet been implemented, these emission estimates are reasonably valid for 2005.

Taking together the available historical and current information on mercury emissions in Florida, it is estimated that anthropogenic mercury emissions in Florida are likely on the order of approximately 5,000 pounds annually.

Table FDEP-15b presents available information on reported mercury emissions in South Florida from the 2006 Annual Operating Reports (AOR). These data reflect sources that provided information on mercury emissions and as indicated above do not reflect all Hg emissions. The total AOR Hg emissions reported in South Florida were 0.89 tons or 1,774.8 pounds. As noted above, this estimate does not include many of the anthropogenic sources determined in the 1993 study. Similar to the statewide anthropogenic mercury emissions estimate in this response, the anthropogenic mercury emissions in South Florida are estimated to be on the order of 3,500 pounds per year.

Table FDEP-15c (South Florida) does not reflect the potential mercury emissions authorized by FDEP permits. Many sources in Table FDEP-15c do not have mercury emission limits so potential emissions are not limited. Table FDEP-15b presents the potential Hg emissions authorized in Title V permits for five MSW resource recovery facilities in far South Florida. The total authorized Hg emissions for these facilities are 2,831 lb/yr. The actual emissions from these facilities in 2005 were 462.4 lb, which is 2.5 times higher than FGPP. It should be noted that in terms of heat input, FGPP is about four times larger than all these facilities combined.

FDEP-16. Indicate measures that will be taken to insure that Hg removed by the various air pollution control processes and discharged via the coal combustion by-products, scrubber effluents, etc., does not reenter the environment.

RESPONSE: The AQCS for Glades County will use powdered activated carbon as mercury sorbent. The sorbent has the ability to oxidize mercury on the carbon surface and chemically bound the mercury in the sorbent structure. As explained in the response to FDEP-7, the bulk of the fuel mercury is removed by the ACI/PJFF combination and ends up in the fly ash. The mercury in fly ash has been found by many studies to be very stable and unlikely to re-enter the environment.

If FPL can not remove the additional mercury that is collected by the PAC process in the fly ash or the cement kiln operator can not effectively remove the additional mercury in the cement kiln exhaust, FPL would not authorize its use in a cement kiln. The ash used in concrete will be in a stable form that will not re-enter the environment.

A small fraction of the fuel mercury will be captured in the wet FGD/WESP combination. The AQCS will include the injection of a commercial precipitating agent into the FGD slurry tank. The precipitating agent will combine with the dissolved mercury in the FGD liquor and prevent mercury re-emission. The mercury in gypsum has been found by many studies to be very stable and unlikely to re-enter the environment.

The mercury contained in scrubber effluent will be disposed of with the plant waste water in the underground injection and control system.

FDEP-17. Please provide more information regarding air emissions during the construction phase of the proposed project, including number and types of vehicles, description of heavy equipment, etc. Describe the measures to minimize the effects of construction activities at the site.

RESPONSE: Information on the estimated emissions during construction was provided in Chapter 4.0, Section 4.5 of the Site Certification Application. Table 4.5-1 presents the emission estimates for construction. Section 4.5 and Table 4.5-1 are attached. A summary of the emissions calculations are summarized below.

- Site Preparation, Soil Moving, and Limestone and Aggregate; Batch Drop: Fugitive emissions for soil moving was developed from the estimated cut and fill requirements. The estimated amount was 11,950,400 cubic yards. A density of 90 pounds per cubic feet was used to estimate the total amount of material moved, which was 14,519,732 tons shown in Table 4.5-1. For limestone and aggregate and engineering estimate of the amount of limestone and aggregate was provided by the engineer as 487,800 cubic yards, which using the same bulk density calculated to be 592,677 tons shown in Table 4.5-1. Emissions were estimated using the EPA equation for batch drop operations, the total suspended particulate matter [PM(TSP)] and PM_{10} emission factors for batch drop operations are defined in Section 13.2.4 of AP-42 by the equation:

$$E = k(0.0032)\,(U/5)^{1.3}/(M/2)^{1.4}\ \text{lb/ton}$$

where: E = emission factor, lb/ton;
k = particle size multiplier;
U = mean wind speed [miles per hour (mph)]; and
M = material moisture content (percent).

The particle size multiplier, k, was based on the EPA multiplier of 0.35 was used for PM_{10}. Mean and maximum daily wind speeds were obtained from the Local Climatological Data and hourly data from Fort Myers Airport. The mean annual wind speed used to calculate emissions was 6.9 mph. The moisture content used was 8 percent.

- Site Preparation Grading/Vehicles; Unpaved Roads: The site will have some unpaved area during the site preparation period for earth moving. To estimate fugitive emissions for this activity the total amount of soil material was used to estimate the total number of miles per day during earth moving activities. An amount of 99,983 miles per year was conservatively estimated. The PM(TSP) and PM_{10} emission factors for active coal pile maintenance, derived from Section 13.2.2 in AP-42, are:

$$E = k(5.9)(s/12)^{a}\,(W/3)^{b}\,[(365\text{-}p)/235](\text{lb/vehicle mile traveled})$$

where: E = emission factor (lb/vehicle mile traveled),
k = particle size multiplier,
a,b = particle size exponents,
s = silt content of surface material (percent),
W = mean vehicle weight (ton), and
P = number of days with at least 0.01 inch of precipitation per year.

The particle size multiplier, k, was based on the EPA multiplier 1.5 in developing the PM_{10} emission estimate. The particle size exponents, a and b, were based on the EPA multipliers. For exponent a, the exponents was 0.9 in developing the PM_{10} emission estimate. For b, the exponent was 0.45. The coal silt content was assumed to be 2.2 percent and the silt content was assumed to be 5 percent and the mean weight was 35 tons. A control level for watering of 90 percent was used.

- Site Preparation Equipment and Foundations/Installation: Emissions form these vehicles were based on diesel engines. Since it is uncertain the exact type of engine, an average fuel use rate of 5 gallons per hour from the Caterpillar Handbook was used. It was estimated that up to 51 pieces of heavy equipment would be used, 10 hours per day, 5 days per week and 52 weeks per year. The amount of estimated fuel use was estimated to be 663,000 gallons per year. The EPA Non-Road Tier 3 emission requirements were used to estimate emissions of PM_{10}, NO_x, SO_2, CO and VOC. These emission factors were: 0.15 gram/hp-hr for PM_{10}, 2.7 gram/hp-hr for NO_x, 0.05 lb/MMBtu for SO_2 (assumed off-road diesel) 2.6 gram/hp-hr for CO and 0.3 gram/hp-hr for VOC. The emissions in grams/hp-hr were converted to pounds per million Btu using an average engine size of 510 brakehorsepower. For foundations and installation a fuel usage of 173,447 gallons/year was conservatively estimated based on the continuous operation of 14 cranes and 10 compressors. The estimate included cement truck hauling. The EPA emission factor Non-Road Tier 3 emission requirements indicated above were used to estimate emissions from foundations and installation.

- Vehicle Traffic: During construction vehicle traffic will utilize paved roads within the site. An estimate of 6,000 miles per day, 5 days per week, 52 weeks per year was used to estimate emissions, which represents the 1,564,286 miles per year. The PM(TSP) and PM_{10} emission factors for vehicle transportation on paved roads was derived from Section 13.2.1 in AP-42, are:

$$E = (k\,(s/12)^a\,(W/3)^b - C)\,(p/4 \times 365)](\text{lb/vehicle mile traveled})$$

where: E = emission factor (lb/vehicle mile traveled);
k = particle size multiplier;
a,b = particle size exponents;
s = silt loading (g/m2);
W = mean vehicle weight (ton);
C = exhaust, brake, and tire correction factor (0.00047); and
p = number of days with at least 0.01 inch of precipitation per year (113 inches).

The particle size multiplier, k, was based on the EPA multiplier of 0.016 in developing the PM_{10} emission estimates. The particle size exponents, a and b, were based on the EPA multipliers. For exponent a and b, the exponents were 0.65 and 1.5, respectively, for the PM_{10} emission estimates. The silt loading was assumed to be 8 g/m^2 based on AP-42. The average vehicle weight was 2 tons. Watering as necessary was assumed.

As described in Section 4.5 of SCA Chapter 4.0, FPL will follow the requirements FDEP Rule 62-296.320(4)c F.A.C. to minimize emission of FGPP during construction. This includes watering and other measures identified in Chapter 4 of the SCA.

FDEP-18. Is there a plan to minimize construction and transportation equipment emissions by using ultra low-sulfur diesel fuel and minimizing idling?

RESPONSE: FPL will make it a policy that construction equipment use ultra low sulfur diesel fuel (i.e., 15-ppm sulfur by weight) to the greatest extent practicable and minimize unnecessary idling. The ultra low-sulfur diesel fuel is now becoming available and FPL expects that when construction activities begin this type of fuel will be readily available.

FDEP-19. Please provide more information regarding the types of vehicles and equipment used during operation of the proposed facility. Will there be a commitment to minimizing pollution by reducing idling and utilizing the use of ultra low sulfur fuel? Further, provide a detailed assessment of all traffic, including vehicle used, purpose of vehicle and miles traveled.

RESPONSE: There will be intermittent heavy equipment used at the site including: a bulldozer in the emergency fuel reclaim area, a diesel train engine that will move rail cars around the site (not part of a delivery train), five 25 ton tri-axle dump trucks to haul byproducts to the BPSA when needed, a bulldozer and compactor in the BPSA, and a small fleet of vehicles used for personnel movement around the site.

FDEP-20. Describe the purpose and duration and emission characteristics of the batch plant shown in Figure 2-1 of the application.

RESPONSE: The purpose of the batch plant is to provide concrete for the structural components of FGPP. Cement and aggregate can be provided to the FGPP site in bulk quantities. Concrete can be made nearby the areas requiring concrete thus eliminating the traveling of cement trucks to the FGPP site. The duration of the batch plant is not expected to last more than 24 months. A batch plant cement contractor has not been selected. However, the plant will meet the requirements of FDEP Rule 62-296.414. It is possible that such facility may have a general permit as from FDEP under Rule 62-210.300(4)c.2, F.A.C. Emissions from the batch plant were estimated in Table 4.5-1 of the SCA using AP-42 emission factors for cement, mixer and truck. The amount of cement was based on the amount deep foundations and cement required for the AQCS.

FDEP-21. Please expand the narrative description of the process, the coal handling system, limestone and reagent preparation system, and the fly and bottom ash handling system (include each emissions point).

RESPONSE: The following is a description of the material handling operations. Figures 2-6 through 2-9 in the Air Construction/PSD Permit Application present the systems proposed for FGPP. Appendix A presents the emissions calculations. The numbering system for the material handling sources reflect the optimization of the material handling systems during the conceptual design and are not numbered consecutively. Several material handling sources were deleted during the optimization process.

The coal handling system is shown in Figure 2-6 of the Air Construction/PSD Permit application. Fuel will be unloaded in rapid rail unloading system. The rapid rail unloader is an enclosed under ground facility where bottom dump train cars unload fuel on to a variable speed belt feeders rated at 500 to 2,000 tons per hour (TPH). From the variable speed belt feeders the fuel is placed on Conveyor C-1. There are three emissions points associated with the rapid rail unloader. Transfer Point 1 (TP-1) is the fugitive emissions at the point of fuel released to the unloader while TP-3 is the emission point from the variable speed belt feeders to enclosed Conveyor C-1, which is rated at 4000 TPH. Enclosed in this case means the conveyor will have side shields and covers along the entire length to minimize fugitive emissions. Emission Point 45 [EP-45; 18,000 cubic feet per minute (cfm)] ventilates the rapid rail unloader and its emissions are accounted for as a batch drop.

From the rapid rail unloading system, fuel will be transferred to a Transfer Tower #1 on enclosed Conveyor C-1 where fuel can be diverted to three areas: 1. Active stockout piles, 2. Inactive stockout pile and 3. Crusher Tower. Transfer Tower #1 will be enclosed with fugitive sources TP-4 and TP-9, and will be ventilated with an exhaust fan EP-46 (2,800 cfm).

Fuel diverted to the active stock piles uses enclosed Conveyor C-2 rated at 4,000 tph where fuel can be diverted to three active piles. The transfer of fuel to the active piles uses a tripper gallery with an associated fugitive source TP-5. Wind erosion occurs from the piles as source Fugitive 6 (F-6). The active coal storage area will maintain sufficient fuel for about 7 days of full-load operation by both units.

Fuel diverted in Transfer Tower #1 to the inactive storage area uses Conveyor C-3, Transfer Tower #2 and Conveyor C-4. Conveyor C-3 is rated at 4000 tph. Transfer Tower #2 will be enclosed with an exhaust fan EP-47 (3,750 cfm). A telescoping chute is used to transfer fuel to the stockout pile where fuel in placed in the inactive storage area. These emissions are associated with TP-11. Fugitive sources F-12, F-13 and F-14 account for wind erosion from the piles. The inactive pile in not used during operation and will be sealed with a sealant to encapsulate the fuel. The inactive storage area will maintain sufficient fuel for up to 60 days of full-load operation by both units.

Fuel is reclaimed from the active storage areas using a portal unloading system with two reclaimers; Portal Reclaimer A and Portal Reclaimer B. From the Portal Reclaimers the fuel will be conveyed on Conveyor C-8 rates at 2,000 TPH to the Crusher Tower, which is enclosed. These reclaimers have associated transfer points for transfer of fuel onto a reclaim conveyor (TP-28 and TP-27).

In the event coal is reclaimed from the inactive fuel area, fuel is loaded from a front end loader onto a 2,000 TPH feeder is used to transfer fuel to Conveyor C-9. The feeder has two transfer points (TP-28 and 29). Conveyor C-9, which is rated at 2,000 TPH, transfers fuel to the Crusher Tower.

Fuel diverted from Transfer Tower #1 directly from the rapid rail unloader to the Crusher Tower uses enclosed Conveyor C-5 rated at 4,000 TPH.

The enclosed Crusher Tower has a surge bin where fuel from Conveyors C-5, C-8 and C-9 is placed prior to crushing. There are four enclosed crushers rated at 1,000 TPH. The enclosed Crusher Tower has three ventilation fans (EP-61, EP-61A, and EP-61B). EP-61 ventilates the surge bin at 1,000 cfm and has a vent filter with transfer points TP-32 and TP33. EP-61A and EP-61B (15,000 cfm each) have six associated batch drop locations (TP-35, TP-35A, TP-36, TP-36A, TP-37, and TP-38).

After crushing, the fuel is then conveyed using Conveyors C-11A and C11B to an enclosed Tripper House. In the Tripper House, fuel can be diverted to the 12 storage silos adjacent to the boilers. There are six transfer points within the Tripper House (TP-39, TP-40, TP-41, TP-42, TP-43 and TP-44) where emissions are collected using one exhaust fan for each unit rated at 23,000 cfm using dust collectors (EP-52 and EP-53).

Limestone used in the wet FGD system will be unloaded using a bottom-dump system (Figure 2-7). The bottom-dump system is an enclosed under ground facility where bottom dump train cars unload limestone on to a variable speed belt feeders. From the variable speed belt feeders the fuel is placed on Conveyor L-1. There are two emissions points associated with limestone unloading. Transfer Point 1 (TP-54) is the fugitive emissions at the point of limestone released, while TP-55 is the emission point from the variable speed belt feeders to enclosed Conveyor L-1, which is rated at 1,000 TPH. The underground bottom-dump system is ventilated using exhaust fan EP-68 (3,000 cfm). Conveyor L-1 transfers limestone will to a covered active storage pile using a telescoping chute (TP-56). Emission point F-57 accounts for the wind erosion from the storage pile. About 60 days storage will be maintained for the operation of the units. Bulldozers and/or front-end loaders will be used as necessary for reclaim and storage pile maintenance. Reclaimed limestone is placed onto a 400-TPH belt feeder that transfers limestone to Conveyor L-2. The batch drop locations associated with the belt feeder are TP-61 and TP-62. Limestone that is transferred using enclosed Conveyor L-2 is conveyed to the limestone preparation building and placed into day bins for each unit. Each day bin has exhaust fans rated at 1,000 cfm (EP-65 and EP-66) with dust collection for TP-63 and TP-64.

Figure 2-8 presents the byproduct handling systems. Economizer ash and fly ash from the air heaters and fabric filters will be pneumatically conveyed to storage silos for each unit. There will be two storage silos per unit. Each silo is equipped with an exhaust fan rated at 3,000 cfm and baghouse (EP-70, EP-70A, EP-72 and EP-72A). Fly ash that is recycled for cement or other purposes will be transported offsite in enclosed tanker trucks or rail cars with air ventilated out of the baghouses. Any fly ash stored in the by-product storage area will be mixed with water (e.g., pug mill), unloaded into covered trucks (TP-69, TP-69A, TP-71 and TP-71A), and transported to the onsite byproduct disposal area.

Bottom ash from the boilers will be collected and directed to the storage bunkers. Either a wet or dry bottom ash system will be used. The wet bottom ash system will be collect bottom ash using a submerged conveyor and sluiced to the storage bunkers, one for each unit (TP-73, TP-76, F-74 and F-77). From the bunkers, the bottom ash is placed in trucks using front end loader and transported to the by-product storage area or transported offsite for use as an aggregate.

After dewatering, FGD byproduct (gypsum) will be conveyed from the gypsum dewatering building to a storage shed using Conveyors G-1 and G-2 rated at 100 TPH each. In the gypsum storage areas there are two transfer points (TP-79 and TP-81) and fugitive emissions associated with each pile (F-84 and F-85). Front-end loaders will be used to load gypsum onto trucks for transport to the byproduct storage area or onto rail cars.

If a dry bottom ash system is used, it will continuously collect dry bottom ash in a hopper located directly beneath each boiler. The dry bottom ash will be removed from the boiler using either an enclosed air-cooled dry scraper conveyor or a vibrating conveyor (see Figure 2-9). The bottom ash would be passed through a crusher and forwarded into a bottom ash bin located adjacent to the boiler. Bottom ash would then be pneumatically transported to a bottom ash storage silo with bin vent filters. The dry bottom ash would be unloaded from the silo into enclosed bulk transport trucks for sale as aggregate or for transport to the byproduct storage area. In the event of a crusher failure, an emergency chute would be provided to direct bottom ash into a bunker or truck at grade for disposal in the byproduct storage area or staged for recycling. All components are air cooled and the seal between the bottom ash hopper and the boiler is maintained using an expansion joint. Because the dry bottom ash system is enclosed, the emissions from this operation will be less than the wet system.

Appendix A presents the emissions calculations for all sources. The maximum amount of materials for the range of fuels proposed for FGPP was used in the calculations. Table A-1 presents a summary of material handling emissions. Tables A-2 and A-3 present information on Emission Points (EPs), which are either based on AP-42 emission factors or exit grain loading from the baghouses. Stack information is provided. Table A-4 presents a summary of emissions from batch drop activities referred to as Transfer Points (TPs). Table A-5 presents a summary of emissions from Fugitive (F) sources including wind erosion and vehicle travel. Table A-5 presents detailed information on the calculation of emissions from batch drop activities for fuel (coal) handling. Table A-6 presents detailed information on the calculation of emissions from batch drop activities for limestone handling. Fly ash and bottom ash handling emissions are presented in Table A-7. Emission calculations foe gypsum handling batch drop activities are presented in A-8. Wind erosion emission calculations are presented in Table A-9 for fuel, limestone, gypsum, bottom ash and byproducts. The fugitive emission calculations for pile maintenance and vehicles on unpaved areas are presented in Table A-10. Emission calculations for vehicles on paved roads are presented in Table A-11. Note that these calculations are based on all the byproducts leaving FGPP by truck. Tables A-12 and A-12a present the parameters used to perform calculations using AP-42 emission factors presented in Section 2 of the Air Construction/PSD Permit Application.

FDEP-22. What activities are contemplated for the train/engine repair location? Are there any emissions associated with this activity?

RESPONSE: The activities conducted in train/repair location will be related to the repair of coal cars. There will be no emission units associated with this activity other than minor insignificant activities meeting the requirements of Rule 62-210.300(3), F.A.C. Such insignificant activities may include the minor use of lubricants and coatings.

FDEP-23. The application listed petroleum coke and U.S. and imported bituminous coal. It states (page 2-1) that the units will co-fire up to 20 percent by weight petroleum coke with coals and that the amounts of each type will vary depending of economic conditions. What combination of fuels was used to calculate emissions? What is the worst case scenario?

RESPONSE: The air emissions were calculated based on the range of coals shown in Table 2-1. For example, sulfur content for the combination of Central Appalachian and Imported bituminous coals and co-firing 20 percent Petroleum Coke shown in Table 2-1 was the basis for the performance wet-FGD system. The fabric filter system for particulate removal would accommodate the ash contents consistent with the data shown in Table 2-1. Overall, the worst-case design is shown in Table 2-1 as the combination of Central Appalachian and Imported bituminous coals and co-firing 20 percent Petroleum Coke.

FDEP-24. Please identify the likely sources of the various fuels (coal and petcoke) mentioned in the application.

RESPONSE: The exact sources of fuels to be used at this time are not known. FPL will manage the fuel contracts based on a blend of long term, short term and spot market purchases of worldwide sources of bituminous coals and pet coke products that fall within the range of fuel specifications that were presented in Table 2-1 of the PSD application. Likely sources include coals from Central Appalachia and South America due to the geographic location of the plant. Petcoke would likely come from the U.S. gulf coast and Caribbean basin.

FDEP-25. The BACT proposal for NO_X is stated as Advanced Combustion Technology (ACT) and SCR. Is the ACT a combination of low NO_X burners, overfire air or reburn or any other technology? Please explain.

RESPONSE: The advanced combustion technology proposed for this project includes a combination of advanced low-NO_x burners and injection of overfire air to stage the combustion. The current design includes 48 advanced low-NO_x burners at 8 corners and 6 elevations. During commissioning period, the units will be tuned and optimized, and the boiler operation data such as NO_x, unburned carbon (LOI), will be obtained. Typical tuning items include the following:

- Flue gas traverse test
- Excess O_2 concentration variation test
- Windbox damper opening variation test
- Additional air damper opening variation test
- Main burner nozzle angle variation test
- Windbox inlet damper opening variation test
- Air/Coal ratio variation test
- MRS rotating speed variation test (pulverized coal fineness variation test)
- Optimum condition test

Expected stoichiometry at the burner zone area is within a range of 0.80 to 0.92. The remaining air will be supplied as overfire air.

Gas reburn is not proposed for this project. The above combination in conjunction with the SCR ensures the NO_x limits will be met.

FDEP-26. Provide the protocol for the start up and shutdown to minimize emissions and quantify emissions during this period.

RESPONSE: A preliminary startup shut down minimization protocol is presented in Attachment FDEP-26. Upon initial operation FPL will provide to FDEP as part the initial Title V Permit Application a startup protocol. This is consistent with the requirements in FDEP Form No. 62-210.900(1), I. Emission Unit Additional Information, Item 4, Procedures for Startup and Shutdown. As stated in the application form, this information is required for operation permits. As discussed in Section 2.5 of the Air Construction/PSD Permit Application, because of low operation, the use of ultra low sulfur distillate oil and the in-service of the fabric filter, wet-FGD and wet-ESP, the total emissions during startups will not exceed the mass emissions if the units had been operating at 100 percent load at the emission rate proposed for FGPP.

FDEP-27. Provide estimates of and any considerations given to carbon dioxide emissions. Advise of any studies or pilot demonstrations projects in which FPL participates or plans to participate.

RESPONSE: FPL and our parent company FPL Group has given great consideration to the topic of carbon emissions. FPL Group is proud to have one of the lowest carbon emission rates (lb/MWhr) within the electric utility industry. If all electric utilities in America were operating at a CO_2 emission rate comparable to FPL Group's, the nation would be able to meet Kyoto Protocol today and in 2013 after FGPP becomes operational.

FGPP is designed with the most efficient, reliable coal-fired boiler units available, resulting in the use of less coal per unit of electricity produced. Carbon dioxide emissions are thereby minimized by maximizing efficiency. Coal is a very important fuel source for the generation of electricity in the United States. Adding this coal-fired facility is critical to meet the need for fuel diversity in Florida and to help stabilize fuel costs for the citizens of Florida.

With regard to CO_2 emissions, the average expected CO_2 emissions will be approximately 14 million tons per year. The project is designed with space available for installation of future carbon capture equipment should the technology become commercially available.

With respect to CO_2 studies and demonstration projects, FPL Group participates in carbon reduction programs in the United States such as USEPA's Climate Leaders. This program was designed to encourage the voluntary reporting and reduction of greenhouse gas emissions. FPL Group was one of the first electric utilities in the U.S. to join. FPL Group was also one of five electric utilities to join World Wildlife Fund's PowerSwitch! Program. As part of this program FPL Group will support reductions of greenhouse gas emissions and improve our generation efficiency 15% by the year 2020. This generation efficiency improvement will reduce the overall emission rate of CO_2 throughout the company's generating system by 2020 including the addition of the highly efficient coal generation proposed for FGPP.

FPL Group is also a partner in the US Climate Action Partnership (USCAP), which is an alliance of major American businesses and four leading environmental groups jointly calling for swift federal action on reducing greenhouse gas emissions and speeding the adoption of climate-friendly technology. FPL participates in the carbon capture and sequestration research subgroup of the Electric Power Research Institute, which is aimed at advancing carbon control technology.

FDEP-28. Please evaluate and provide information regarding the feasibility of dry cooling techniques versus mechanical draft cooling towers with drift eliminators.

RESPONSE: Air-cooled condensers, also referred to as dry cooling towers, are a form of closed cycle condenser cooling using air as the cooling medium. This technology has not been used in Florida due to the warm climate and results in the decrease of thermal efficiency in the steam cycle and increased internal power usage. Dry cooling systems are less efficient at removing heat than the wet cooling systems, particularly at ambient temperatures experienced in Florida. As the air temperatures rise, the rate at which the dry cooling systems can transfer thermal energy from the steam to air decreases. This leads to higher energy costs for cooling fans and higher steam turbine backpressures since the steam must be condensed at a higher temperature. Therefore, the climatic conditions experienced in Florida and in hotter weather conditions experienced in the summertime (i.e., peak electrical demand), there is less electricity produced with the dry cooling compared to the wet cooling systems.

For FGPP, dry cooling systems at an ambient temperature of 75°F would consume an additional 46.8 MW for both units and lower a heat rate by about 2.4 percent. During hot days' 95°F ambient temperature, the dry cooling systems require 149 MW and 8 percent higher heat rate than the mechanical draft wet cooling systems proposed for the FGPP.

Power used by air-cooled condensers and loss of heat rate would have collateral environmental and economic disadvantages. On average, this lost power would be 409,968 MW-hrs per year or enough power to serve about 34,000 residential customers with electrical power. The power required for dry cooling will result in air emissions that would otherwise not occur to supply the generation required for dry cooling. The emissions increase for SO_2, NO_x and PM_{10} would be 74, 93 and 24 tons/year, respectively. In contrast, the maximum potential PM_{10} emissions from the cooling towers were conservatively estimated to be 15.5 tons/year. High efficiency drift eliminators have been proposed to reduce the particulate emissions. The drift eliminators are designed to achieve 0.0005 percent drift rate, which has been accepted as BACT on many recent projects (Seminole Generating Station Unit 3, West County Energy Center, Turkey Point Unit 5, Martin Unit 8, and Manatee Unit 3).

Moreover, there is a substantial economic impact associated with air-cooled condensers. This includes an estimated increase in capital cost of about $140 million. The net present value increase for the dry cooling systems is approximately 600 million dollars compared to the wet cooling systems. FGPP selects mechanical draft cooling towers with high efficiency drift eliminators as method of choice for cooling since they are less costly to build and operate, generate electricity more efficiently and less impact to the environments than would have been dry cooling systems.

In addition, air cooled condensers occupy a very large area (over 2 acres) and typically generate considerable noise due to the numerous elevated fans.

FDEP-29. Please total up the hazardous air pollutants (HAPs) estimated for the project.

RESPONSE: Table FDEP-29 (Attachment FDEP-29) presents a summary of the estimated emissions of Hazardous Air Pollutants (HAPs) presented in the Air Construction/PSD Permit Application, Tables HAPS-1 through HAPS-4 of Appendix A. This application is contained as Appendix 10.1.5 of the Site Certification Application. The information for HAPs was developed using AP-42 emissions factors and presents a conservative estimate of emissions. Since a coal source is not known, the upper 95 percent confidence interval for Central Appalachian coal was used in estimating emissions. Conservative assumptions were also used in estimating removal rates for halogens.

FDEP-30. What are the distances between the proposed project and the following geographical features and municipalities: the City of Moore Haven; Clewiston; Lake Okeechobee; Brighton Seminole Reservation; Everglades National Park; and Big Cypress National Preserve? Show these relationships on a map.

RESPONSE: See Attachment FDEP-30 for this information.

FDEP-31. In general, the results of the ambient air quality analyses should be displayed in more reader friendly graphical formats on maps that include geographic features and municipalities to allow a better appreciation of the degree to which they are affected by the proposed project. This will make the subject matter more readily understandable to all readers including experts and laymen.

RESPONSE: See Attachment FDEP-31, Figures 1 through 5 for this information.

FDEP-32. Section 6.5 of the PSD Report states that the land use data of the Ft. Myers National Weather Service station was compared to the land use of the proposed project site. It also states that this comparison found that land use values were similar between the Ft. Myers station and the project site. Please provide these data to the Department for verification purposes.

RESPONSE: The general surface land use in the vicinity of the Ft. Myers Southwest International Airport is very similar to that found in the vicinity of the Project site. The surface land use features within a 3-km radius of each site were evaluated using the AERSURFACE program which processes surface land use parameters for use in AERMOD. These parameters are used to estimate the surface boundary layer conditions that characterize plume dispersion. These parameters include: albedo, which is an indicator of the mean reflectivity of the land surface; Bowen Ratio, which is an indicator of average moisture conditions; and surface roughness, which is an indicator of the mean obstacle height. For Ft. Myers, the 3-km radius was centered on the meteorological station. For the Project, the 3-km radius was centered on the proposed boilers' stack. The average parameter values are as follows:

Location	Albedo	Bowen Ratio	Surface Roughness (m)
Ft. Myers	0.19	0.88	0.20
Project	0.19	1.00	0.22
Range	0 to 1.0	0 to >1.0	0 to >1.0

These results show that the values for albedo, Bowen Ratio, and surface roughness are comparable to those at Ft. Myers. Given that these land use values are similar, it is expected that the differences in processing the meteorological data using the land use around the Project site or Ft. Myers would not produce significantly different maximum predicted impacts for the Project. As such, the land use in the vicinity of the Project is considered to be very similar to and representative of those in the vicinity of the Ft. Myers Southwest International Airport.

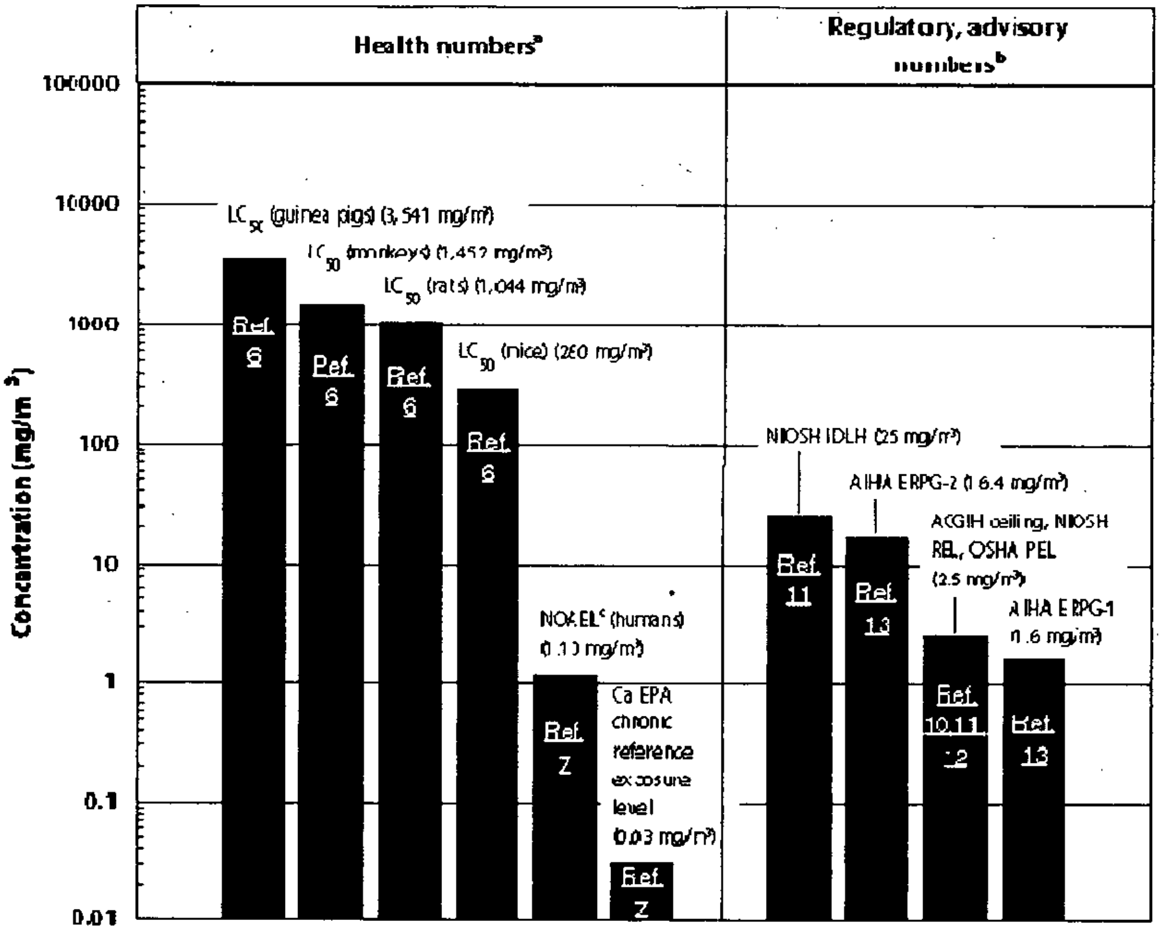
FDEP-33. The proposed project is PSD for VOC and NO_X, which are precursors to the pollutant ozone. In the PSD Report, impacts from the proposed project with regards to ozone are solely evaluated with respect to vegetation, specifically in the Class I areas. VOC emissions in excess of 100 TPY require an ambient air quality analysis for ozone. Please submit an ambient air quality analysis for ozone.

RESPONSE: Please refer to the responses to FDEP-8 and FDEP-9.

FDEP-34. The proposed project triggers PSD for Total Fluorides. There are modeled concentrations for HF impacts listed in Table 6-7 of the PSD Report. Please provide additional information regarding the impact of Total Fluorides. For example, how would a 24-hour concentration of 0.028 micrograms per cubic meter impact the surrounding Class II area?

RESPONSE: AP-42 emissions factors (Table 1.1-15) and studies by EPRI indicate that for fluorides, the primary emission is in the gas phase emitted as hydrogen fluoride. The maximum impact of HF was determined and presented in Table 6-7 of the Air Construction/PSD Permit Application. The maximum annual average concentrations of hydrogen fluoride resulting from FGPP are 0.028 $\mu g/m^3$ for a 24-hour averaging time. There are no ambient air quality standards for HF. However, EPA (1999) has summarized health criteria in milligrams per cubic meter (mg/m^3), which is a thousand times less than ug/m^3. The bottom value in the chart is 0.01 mg/m^3, which is 10 ug/m^3 or about 357 times higher than the maximum predicted impact.

Hydrogen Fluoride



Footnotes:

AIHA ERPG--American Industrial Hygiene Association's emergency response planning guidelines. ERPG 1 is the maximum airborne concentration below which it is believed nearly all individuals could be exposed up to one hour without experiencing other than mild transient adverse health effects or perceiving a clearly defined objectionable odor; ERPG 2 is the maximum airborne concentration below which it is believed nearly all individuals could be exposed up to one hour without experiencing or developing irreversible or other serious health effects that could impair their abilities to take protective action.

ACGIH TLV ceiling--American Conference of Governmental and Industrial Hygienists' threshold limit value ceiling; the concentration of a substance that should not be exceeded during any part of the working exposure.

LC_{50} (Lethal Concentration$_{50}$)--A calculated concentration of a chemical in air to which exposure for a specific length of time is expected to cause death in 50% of a defined experimental animal population.

NIOSH REL--National Institute of Occupational Safety and Health's recommended exposure limit; NIOSH-recommended exposure limit for an 8- or 10-h time-weighted-average exposure and/or ceiling.

NIOSH IDLH -- NIOSH's immediately dangerous to life or health concentration; NIOSH recommended exposure limit to ensure that a worker can escape from an exposure condition that is likely to cause death or immediate or delayed permanent adverse health effects or prevent escape from the environment.

OSHA PEL--Occupational Safety and Health Administration's permissible exposure limit expressed as a time-weighted average; the concentration of a substance to which most workers can be exposed without adverse effects averaged over a normal 8-h workday or a 40-h workweek. The health and regulatory values cited in this factsheet were obtained in December 1999.

Health numbers are toxicological numbers from animal testing or risk assessment values developed by EPA. [b] Regulatory numbers are values that have been incorporated in Government regulations, while advisory numbers are nonregulatory values provided by the Government or other groups as advice. OSHA numbers are regulatory, whereas NIOSH, ACGIH, and AIHA numbers are advisory[c] This NOAEL is from the critical study used as the basis for the CalEPA chronic reference exposure level.

As noted from the EPA summary, the maximum HF impacts are orders of magnitude lower than the lowest criteria cited in the figure. Fluorides can also have an impact on vegetation. Exposure of sensitive plant species to 0.5 $\mu g/m^3$ of fluorides for 30 days has resulted in significant foliar necrosis (EPA, 1990). The maximum predicted 24-hour HF impact level is much less than the 30-day average. Note that the maximum annual average HF impact is 0.003 ug/m^3. Due to the extremely low hydrogen fluoride emission rates, FGPP will not result in adverse impacts to health of vegetation in the vicinity of FGPP and within the PSD Class II area.

FDEP-35. Table 6-7 in the PSD Report shows the emission rates used in the modeling analyses for the proposed project. The long term emission rates are equal to the short term emission rates. The modeling analyses should reflect the worst case scenario. Please model all short term impacts using short term emission rates (i.e. the highest 24-hour emission rate, not 30 day average, for the 24-hour averaging period) for the Class I and Class II areas. Please submit all new modeling to the Department, including a Preconstruction Monitoring Analysis, a Significant Impact and Increment Analysis for all short-term averaging periods.

RESPONSE: The emission rates for the pollutants modeled in the air impact analyses are based on rates that apply to both the short-term and long-term averaging periods, except for SO_2. For SO_2, the short-term emission rates are for averaging periods of 24 hours and longer. Therefore, the modeling analyses that were performed to address the 24-hour and annual average SO_2 impacts for comparisons to the Preconstruction Monitoring levels, significant impact levels, and PSD Class II and I increments are complete.

The maximum 3-hour average SO_2 emission rate is 0.065 lb/MMBtu. Additional air impact analyses were performed to assess the Project's impacts in PSD Class II and I areas for this emission rate. Summaries of these results are presented in revised Tables 6-7 through 6-9 of the PSD Permit Application and revised Tables 5.6.1-1 and 5.6.1-2 of the SCA. As shown in revised Tables 6-7 and 6-8 (Table 5.6.1-1), the maximum 3-hour average SO_2 impact due to the Project is predicted to be less than the significant impact level in the PSD Class II area. Since the Project's 3-hour average SO_2 impacts are not significant, no further modeling is required to address compliance with the 3-hour average SO_2 AAQS and PSD Class II increment. As shown in revised Table 6-9 (Table 5.6.1-2), the maximum 3-hour average SO_2 impact due to the Project is predicted to be greater than the significant impact level in the PSD Class I areas of the Everglades National Park, which is similar to the previous analyses, and also the Chassahowitzka National Wilderness Area. Since the Project's 3-hour average SO_2 impacts are predicted to be greater than the significant impact level, additional modeling was performed to address compliance with the 3-hour average SO_2 PSD Class I increments at both Class I areas. A summary of the cumulative source impact analyses predicted for the Project and background PSD sources is presented in revised Table 6-12 (Table 5.6.1-5). These results show that the maximum SO_2 impacts for the PSD sources are predicted to comply with the PSD Class I allowable increments

In addition, the maximum 3-hour average impact due to the Project predicted at the Big Cypress National Preserve and Biscayne National Park are presented in revised Table 5.6.1-6. As shown in this table, the maximum Project's impacts are also predicted to be less than the significant impact level in these areas.

The Project's maximum 3-hour impacts were also predicted for the AQRV analyses with summaries of the model results for the Everglades National Park and Chassahowitzka National Wilderness Area presented in revised Tables 7-1 and 7-2, respectively.

It should be noted that the Project's and PSD sources impacts were predicted at the PSD Class I areas using the EPA version of the CALPUFF model (Version 5.711a).

FDEP-36. The CALPUFF modeling system was used to model impacts from the proposed project for the Class I areas. However, there are various versions of the model. The VISTAS version was used in the analysis for the Glades Power Park. While this version is accepted for use by the National Park Service, the EPA requires the use of the "regulatory" version (available on the EPA web site) to model the Class I Significant Impact Analysis and Increment, if required. Please model using the preferred EPA version or submit necessary documentation to obtain approval for using the VISTAS version.

RESPONSE: Pursuant to the pre-application modeling protocol and subsequent discussions with the FDEP and NPS, the VISTAS version of the CALPUFF model was used in the PSD Permit Application and SCA to assess visibility impairment and sulfur and nitrogen deposition as well as pollutant concentrations in the PSD Class I areas. Additional modeling has now been performed to assess the Project's impacts using the 5.711a version of the CALPUFF model for comparison to the PSD Class I significant impact levels and increments. Summaries of the Project's impacts and PSD Class I increment impacts based on this modeling are presented in revised Table 6-9 (Table 5.6.1-2) and revised Table 6-12 (Table 5.6.1-5), respectively. As shown in these tables, the maximum pollutant impacts due to the Project are predicted to be nearly identical and slightly lower than those predicted using the 5.711a version of the CALPUFF model than those predicted with VISTAS version. As a result, the conclusions are the same using either version of the CALPUFF model; FGPP does not cause an adverse impact on Air Quality Related Values. It should be noted that the VISTAS version of the model was used in the original analyses in order to estimate the Project's impacts using one consistent model.

Based on comments received from the FDEP, the National Park Service has recently requested that the 5.711a version of the CALPUFF model also be used in the AQRV analyses. As a result, the Project's impacts were predicted at the PSD Class I areas using the 5.711a version of the CALPUFF model (see the response to Comment FDEP-35).

FDEP-37. Are the Results in Table 7-6 of the PSD Report for Method 6 results of modeling with the Initial or New IMPROVE equation?

RESPONSE: The visibility impairment results for Method 6 that are presented in Table 7-6 are based on the New IMPROVE equation.

FDEP-38. The PM modeling including fugitive emissions has stack diameter inputs of 42 feet while Table 2-3 in the PSD Report states that the diameter will be 30 feet. Please correct the modeling or the Table to reflect the correct diameter. The modeled diameter of the cooling tower cells and emission rates do not correspond with Table 2-4 as well.

RESPONSE: The stack for the Project consists of two flues, one for each boiler. The modeling for the Project stack is based on an "effective" stack diameter of 42 ft which is estimated from the combined areas using the diameter of 30 ft for each flue. The merging of the two flues into one stack diameter is allowed under the Good Engineering Practice (GEP) stack height regulations for emissions sources that have less than 5,000 TPY of SO_2 emissions.

For the cooling towers, there are 32 cells per tower, with little separation distance among the cells. In cooling tower impact analyses, multiple cells are typically merged together to account for this minimum separation distance. For these analyses, two of the cells were combined and modeled with an effective diameter based on the combined areas of the individual cells.

In Table 2-3, the emissions were doubled to account for the combining of the stacks in the PM modeling analysis.

In Table 2-4, the emissions were doubled to account for the combining of the two cooling tower cells in the PM modeling analysis.

FDEP-39. The PM modeling including fugitive emissions shows an Emission Factor for Wind Speed Emission Rate Variation of 1 for higher wind speeds for source ID AREA9WE, AREA2WE and BYPRODWE. Please explain.

RESPONSE: The emission factor for these sources is based on the PM emissions occurring when the wind speed is greater than 12 mph (5.4 m/s) (see Table A-9 in the PSD Permit Application). This was accounted for by setting the Wind Speed Emission Rate Variation to 1 in the model for wind speed categories of 12 mph and higher.

FDEP-40. Please explain how the Initial Vertical Dimension was determined for the volume sources.

RESPONSE: The volume sources in the model represent truck traffic traveling on the entry road on the Project site. The initial vertical dimension for the volume sources are based on an initial wake height of 20 ft to account for the truck height and wake effect of the truck movement. Based on the AERMOD User's Manual, the initial vertical dimension in the model is estimated by using the initial height and dividing by 2.15. In this case, the initial wake height of 20 ft was divided by 2.15 to produce an initial vertical dimension of 9.3 ft for these volume sources.

FDEP-41. Please provide further information regarding Railcar emissions. For example, emission source ID EP-45 includes railcar unloading, TP-3, according to Table A-2. However, Table A-3 shows railcar loading as TP-1, which is not a part of any emission points listed in Table A-2. Further, please explain which source ID's in the modeling analysis includes emissions listed in Table A-3.

RESPONSE: The sources listed in Table A-3 were modeled as area sources since they are fugitive emissions due to transfer operations. The emissions from several of these activities were combined into one emission rate that was then modeled as an area source. A summary of the individual emission sources and the area sources that included the combined emission rates is presented in Table FDEP-41, Attachment FDEP-41.

FDEP-42. Please provide further information regarding the truck/bulldozer traffic emissions. Please provide the truck traffic source ID's used in the modeling analysis.

RESPONSE: The truck traffic IDs are presented in the AERMOD model files as BYPROD01 through BYPROD138. The emission rate assigned to each modeled source is identified in Table FDEP-41.

FDEP-43. Table A-4 in the PSD Report lists 2 inactive coal piles, F-14 and F -13. However, Table A-9 (page 1 of 3), states that F-14 is an active coal pile and Table A-9 (page 2 of 3) only has one inactive pile, F-13. Please clarify and note which Source ID is used in the modeling for these emissions.

RESPONSE: The source IDs for these emissions are presented in Table FDEP-41.

FDEP-44. Table A-4 in the PSD Report includes all emissions for all bulldozers and front end loaders listed in Table A-10 except for Bottom Ash Handling F-76. Was F-76 accounted for in the material handling operation emissions?

RESPONSE: The emissions from the Bottom Ash Handling F-76 were accounted for in the modeled emissions. See Table FDEP-41.

FDEP-45. Table 6-6 in the PSD Report lists the building dimensions used in the modeling analysis. The modeling shows 19 of the 22 listed in the table. The 3 missing are the Railcar Area, the Limestone Track Hopper and the second Coal Transfer House. Please add these buildings to the modeling analysis. Should the Administration, Warehouse and Maintenance buildings be added to the modeling analysis?

RESPONSE: The dimensions for the Railcar Area and Limestone Track Hopper are for activities that will occur in these areas but not related to solid building structures. These dimensions were used to account for the PM fugitive emissions from these areas which were modeled as area sources (see Table FDEP-41). The second Coal Transfer House is a tall, narrow structure that will not significantly affect building downwash conditions for the sources modeled in the analysis. Because the modeling accounted for PM emissions and building dimensions from the first Coal Transfer House as the primary emission source since the second Coal Transfer House is not normally used, the inclusion of this structure will not change the maximum predicted PM impacts, which are primarily due to truck traffic handling the byproduct.

The Administration, Warehouse, Maintenance buildings will have low building heights that will not affect the modeled sources and do not need to be included in the analysis.

FDEP-46. The receptor grids for the SO_2 and PM_{10} Increment analyses have 450-500 receptors. The PM_{10} analysis only has receptors along the fence-line. Please verify that receptors are placed in "areas," not just "points" of "significance."

RESPONSE: For both SO_2 and PM_{10} analyses, the receptors are placed in areas in which the Project's impacts were predicted to be greater than the significant impact levels. It should be noted that Project's PM10 impacts were predicted to be greater than PM_{10} significant impact levels only in a very small area along the eastern plant property where the entrance road is located. These impacts were primarily due to PM emissions from the truck traffic.

FDEP-47. Where in the stack will CEMS be placed? Where will stack sampling platforms be located?

RESPONSE: The CEMS will be located inside a CEMS building at the base of the stack. The probes and sampling platforms are anticipated to be placed approximately 210 ft above grade based on Performance Specifications 2 of 40 CFR Part 60, Appendix B. The exact location will be determined during final design.

ATTACHMENT FDEP-1

RESPONSES TO THE QUESTIONS AND COMMENTS FROM THE FEDERAL LAND MANAGER REGARDING THE AIR CONSTRUCTION/PSD PERMIT APPLICATION

United States Department of the Interior
NATIONAL PARK SERVICE

Everglades and Dry Tortugas National Parks
40001 State Road 9336
Homestead, Florida 33034

In Reply Refer to:

N3615

January 18, 2007

A.A. Linero, Program Administrator
Department for Environmental Protection
Permitting South Section
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

We have reviewed the Florida Power & Light (FPL) Prevention of Significant Deterioration (PSD) permit application for the Glades Power Park (GPP) located in Glades County, Florida. The proposed GPP facility would be located approximately 113 kilometers north of Everglades National Park, a Class I air quality area administered by the National Park Service (NPS). The facility would also be located approximately 65 kilometers north of Big Cypress National Preserve and approximately 160 kilometers northwest of Biscayne National Park, both Class II areas administered by the NPS. The facility will be a 1,960 megawatt power plant consisting of two pulverized coal-fired boilers which will burn a blend of coal and petroleum coke. According to the FPL PSD permit application, the GPP facility will emit a total of 3,811 tons per year (TPY) of nitrogen oxide (NO_x), 3,049 TPY of sulfur dioxide (SO_2), 1,281 TPY of total particulate matter (PM), 1,022 TPY of particulate matter less than 10 microns (PM_{10}), 305 TPY of sulfuric acid mist (H_2SO_4), and 260 TPY of volatile organic compounds.

Based on our initial review of the GPP permit application, we find it does not include all of the information we need to assess potential impacts from GPP emissions on sensitive resources at Everglades National Park. We have the following comments concerning the permit application.

PSD Increment and Visibility Concerns

The air quality modeling files and the permit application we received on January 4, 2007, show that FPL based its visibility impacts and 3-hr and 24-hr increment consumption analyses on 30-day rolling average emission rates. FPL used emission rates of 696 lb/hr for SO_2, 870 lb/hr for NO_x, 226 lb/hr for speciated PM_{10} and 69.6 lb/hr for H_2SO_4 in these analyses. These rates are only applicable for the annual increments and acid deposition impacts analyses. Therefore, FPL's visibility impacts analyses for Everglades National Park and its short-term Class I and Class II increment analyses (i.e., the 3-hour and 24-hour SO_2 and 24-hour PM_{10} averaging periods) are incorrect. Thus, FPL should redo its short-term Class I and Class II FDEP-1A increment analyses and its visibility impact analysis (including both filterable and condensable PM) using the correct 3-hour and 24-hour emission rates. Also, if the Class I Significant Impact Levels are exceeded, FPL should perform cumulative Class I increment impact analyses using the correct 3-hour and 24-hour emission limits. If a cumulative Class I impact analysis is completed, we ask that FPL provide information as to how the cumulative increment analyses were conducted. FPL should provide a discussion of the methods used to determine which sources were included in the cumulative inventory, and how it determined changes in emissions from those sources relative to baseline emissions. We also ask that FPL provide us example calculations for the more significant sources. Spreadsheets (in Excel format) should be provided containing the sources in the inventory, their distances from Everglades National Park, and their changes in emissions. In conclusion, based on the incorrect Class I and Class II air quality and visibility analyses in the FPL permit application, the NPS cannot determine the frequency, magnitude and extent of the visibility impacts at Everglades National Park, nor the amount of Class I increment consumed in the park. We ask that FDEP require FPL to conduct these analyses and include them in the GPP permit application.

Sulfate Deposition and Mercury Concerns

Mercury contamination of fish and wildlife is widespread throughout Everglades National Park. Emissions from the GPP facility will increase mercury deposition to the area, increasing the risk of toxic effects to both humans and wildlife. In addition, the modeling analysis for the facility predicts an increase in sulfate deposition to Everglades National Park. Increased sulfate deposition will likely increase methylation of mercury in sediments, with subsequent increased methylmercury bioaccumulation in the food web. **FDEP-1B**

Therefore, we would like FPL to evaluate the impact of increased mercury and sulfate deposition on mercury methylation and subsequent mercury bioaccumulation in Everglades National Park. In addition, we would like FPL to mitigate mercury and sulfate deposition so that mercury methylation and accumulation potential is minimized.

Threatened and Endangered Species Concerns

We are also concerned about the potential effects of GPP emissions on threatened and endangered plants and wildlife protected by the Federal Endangered Species Act. Information regarding threatened and endangered species effects will be pertinent to federal actions or approvals needed before GPP is permitted or commences construction. In order to avoid delays, it may be prudent for FPL to examine potential effects on threatened and endangered species as soon as practical. **FDEP-1C**

Best Available Control Technology (BACT)

Because the short-term (3-hour and 24-hour average) emissions rates are not specified for SO_2 and NO_x, and the averaging period for H_2SO_4 is not identified, we can not properly compare **FDEP-1D** the level of emission control (BACT analysis) to similar facilities that do have appropriate short-term limits. We ask FPL to provide this information in its permit application.

Conclusion

We are concerned that emissions from the proposed GPP facility will cause or contribute to a change in the air quality in Everglades National Park. Specifically, the emissions from the GPP facility have the potential to impact air quality and cause visibility impairment in Everglades National Park. We are also concerned that emissions from the GPP facility have the potential to exacerbate methylmercury conditions and to affect threatened and endangered species.

We ask that you require FPL to redo the air quality modeling analyses and to provide the requested additional information on BACT before deeming the permit application complete. We also ask that you allow us sufficient time to review this and all other relevant information in accordance with the Federal Land Manager notification requirements in 40 CFR 51.307. With the requested information and analyses, we will be in a better position to assess the air quality impacts on sensitive resources at Everglades National Park

Thank you for involving us in the review of GPP's PSD permit application. Please do not hesitate to contact Mr. Dee Morse of our Air Resources Division in Denver (303-969-2817) or me (305-242-7712) if you have any questions concerning the comments provided above.

Sincerely,

Dan B. Kimball

Dan B. Kimball
Superintendent
Everglades and Dry Tortugas National Parks

FDEP-1A. PSD Increment and Visibility Concerns: FPL should redo its short-term Class I and Class II increment analyses and its visibility impact analysis (including both filterable and condensable PM) using the correct 3-hour and 24-hour emission rates. Also, if the Class I Significant Impact Levels are exceeded, FPL should perform cumulative Class I increment impact analyses using the correct 3-hour and 24-hour emission limits. If a cumulative Class I impact analysis is completed, we ask that FPL provide information as to how the cumulative increment analyses were conducted. FPL should provide a discussion of the methods used to determine which sources were included in the cumulative inventory, and how it determined changes in emissions from those sources relative to baseline emissions. We also ask that FPL provide us example calculations for the more significant sources. Spreadsheets (in Excel format) should be provided containing the sources in the inventory, their distances from Everglades National Park, and their changes in emissions.

RESPONSE: The emission rates for the pollutants modeled (PM_{10}, SO_2, NO_x, and SAM) in the air impact analyses submitted in the Air Construction/PSD application are based on rates that apply to both the short-term and long-term averaging periods, except for SO_2. For SO_2, the short-term emission rates are for averaging periods of 24 hours and longer. Therefore, the modeling analyses that were performed to address the 24-hour and annual average SO_2 impacts for comparisons to the Preconstruction Monitoring levels, significant impact levels, and PSD Class II and I increments were completed using the CALPUFF Vistas version as provided in the modeling protocol submitted to FDEP and NPS in June 2006. In addition, as a result of additional comments received from the NPS through FDEP in mid-February 2007, additional modeling analyses were conducted using CALPUFF Version 5.711a. A summary of the results are provided in this response with results shown in Attachment FDEP-35. The modeling files and spreadsheets will be submitted under separate cover due to their volume.

The maximum 3-hour average SO_2 emission rate is 0.065 lb/MMBtu. Additional air impact analyses were performed using this emission rate to assess the Project's impacts in PSD Class II and I areas. Summaries of these results are presented in the attachment to H-35. The maximum 3-hour average SO_2 impact due to the Project is predicted to be less than the significant impact level in the PSD Class II area. Since the Project's 3-hour average SO_2 impacts are not significant, no further modeling is required to address compliance with the 3-hour average SO_2 AAQS and PSD Class II increment. The maximum 3-hour and 24-hour average SO_2 impacts due to the Project are predicted to be greater than the significant impact level in the PSD Class I areas of the Everglades National Park, which is similar to the previous analyses. In addition, the maximum 3-hour average SO_2 impact due to the Project is predicted to be greater than the significant impact level in the PSD Class I area of the Chassahowitzka National Wilderness Area. Additional modeling was performed to address compliance with the 3-hour average SO_2 PSD Class I increments at both Class I areas. A summary of the cumulative source impact analyses predicted for the Project and background PSD sources is presented in the attachment for FDEP H-35. These results show that the maximum SO_2 impacts for the PSD sources are predicted to comply with the PSD Class I allowable increments.

For assessing impacts at the Everglades National Park, data for the background sources were obtained from FDEP and are based on those used in recent PSD modeling analyses (e.g., FPL West County Energy Center). A listing of background SO_2 sources that were used in the PSD Class I analyses and their locations relative to the PSD Class I area are provided in Table 6-4 of the PSD Report. PSD sources located within 200 km of the Class I area were included in the PSD Class I modeling analysis. Detailed SO_2 background source data that were used for the PSD Class I analyses are presented in Appendix C of the PSD Report.

For assessing impacts at the Chassahowitzka National Wilderness Area, data for the background sources were also obtained from FDEP and are based on those used in recent PSD modeling analyses (e.g., Progress Energy, Units 4 and 5 at the Crystal River Plant; Seminole Electric Cooperative, Inc., Proposed Unit 3). A listing of background SO_2 sources that were used in the PSD Class I analyses and their locations relative to the PSD Class I area are provided in Table FDEP-1A-1. PSD sources located within 200 km of the Class I area were included in the PSD Class I modeling analysis. Detailed SO_2 background source data that were used for the PSD Class I analyses are presented in Table FDEP H-1A2.

Comments were received through the FDEP on February 7, 2007, that the National Park Service requested that the 5.711a version of the CALPUFF model be used in the AQRV analyses rather than the VISTAS version identified in the modeling protocol submitted to FDEP and NPS in June 2006. Although this comment was provided by e-mail after the date of the NPS, additional modeling was performed to evaluate the impacts to visibility at the PSD Class I areas using the 5.711a version of the CALPUFF model. These results are presented in Attachment FDEP-36 as Table 7-6.

The results of the additional regional haze analysis for FGPP were assessed using Method 6 and Method 2 with the new IMPROVE algorithm. Method 2 with the initial IMPROVE algorithm was also conducted. The results of this additional modeling did not change any of the conclusions reached regarding regional haze using the more current VISTAS version of CALPUFF. A summary is provided below.

The 8^{th} highest value at the Everglades NP due to FGPP is 4.09. Based on the 8^{th} highest value predicted for FGPP in each year, there are no days during which the regional haze impacts were predicted above the 5-percent. For the Chassahowitzka NWA, the 8^{th} highest value due to FGPP is 3.25. Based on the 8^{th} highest value predicted for FGPP in each year, there are no days during which the regional haze impacts were predicted above 5-percent. Method 6 was also evaluated using the new improve equation in the BART approach. This resulted in lower predicted visibility impairment. It should be noted that in Method 6, days with naturally visibility impairment are not excluded in the analysis. Rather, the monthly relatively humidity and the frequency of visibility impairment (i.e., use of the 98^{th} percentile, equivalent to the 8^{th} highest daily average value) is used as a way to more realistically assess visibility impairment as recognized by EPA (70 FR 39121).

The maximum impact on visibility at the Everglades NP using Method 2 with the new IMPROVE equation is predicted to be 8.14 percent with a total of 6 days out of 3 years above the 5-percent when days with naturally occurring visibility impairment are excluded. For the Chassahowitzka NWA, this method predicts only 1 day out of 3 years above 5 percent (i.e., 5.32 percent). When all days are considered in the analysis, including days when naturally occurring visibility occurs, the maximum impact on visibility at the Everglades NP is predicted to be 9.98 percent with a total of 10 days above 5-percent and at Chassahowitzka NWA is predicted to be 8.14 percent with a total of 5 days above 5-percent.

For completeness, the maximum impacts on visibility with Method 2 with the initial IMPROVE equation are predicted to be greater than 5-percent at the Everglades NP for about 0.8 percent of the time (i.e., 9 days) over the 3-year period. At the Chassahowitzka NWA, the maximum impacts from the FGPP are predicted to be greater than the 5-percent for less than 0.2 percent of the time (i.e., 2 days) over the 3-year period.

Based on the analysis demonstrating infrequent occurrences of regional haze impacts from FGPP under all three modeling methods, it is concluded that FGPP will not have an adverse impact on visibility at either the Everglades NP or the Chassahowitzka NWA.

FDEP H-1B. Sulfate Deposition and Mercury Concerns: We would like FPL to evaluate the impact of increased mercury and sulfate deposition on mercury methylation and subsequent mercury bioaccumulation in Everglades National Park. In addition, we would like FPL to mitigate mercury and sulfate deposition so that mercury methylation and accumulation potential is minimized.

RESPONSE: Mercury methylation in the Everglades is a complex phenomenon that has and continues to undergo significant research. The following provides information on mercury methlyation and the role of mercury and sulfate emissions from FGPP in the Everglades National Park. The results of Golder's evaluation indicate that FGPP's mercury and sulfate deposition will have insignificant impacts on the Everglades National Park. FPL has a long-standing commitment to the environment that has supported, and will continue to support, projects that limit environmental impacts to Florida's ecosystem.

Relationship between inorganic mercury emissions and organic mercury in the environment

The relationship between inorganic mercury emissions and organic mercury in the environment, including fish, is complex (Eisler, 2006). When mercury is emitted from coal-fired power plants it is as an inorganic substance – typically elemental mercury (Hg^0), divalent mercury (Hg^{2+}, also termed reactive gaseous mercury, or RGM), and particulate mercury, and can change form as it travels downwind (Lohman et al., 2006). Inorganic mercury is also emitted from a wide variety of other sources including motor vehicles, incinerators, crematoria, forest fires, deep sea vents, volcanoes, oceans, soils, etc. Although estimates vary, about 30 to 50 percent of the mercury emitted to the atmosphere is due to human activities (Eisler, 2006; USEPA, 2005). All states and countries have some level of mercury emissions; the greatest current levels of human-related emissions appear to be from China (Seigneur et al, 2004). Contamination due to mercury is a world-wide problem.

Mercury in the atmosphere can be deposited onto land or water via either dry deposition (e.g., dust) or wet deposition (e.g., rain, snow) (Dvonch et al., 1999). Wet deposition can result in some forms of mercury coming down closer to emission sources. But mercury deposited to land or water may not remain there; mercury can be re-emitted back to the atmosphere where it is transported further. Thus, once mercury enters the atmosphere, it becomes part of a global cycle of mercury among land, water, and the atmosphere; past activities continue to affect current atmospheric mercury concentrations.

The inorganic mercury that remains in water bodies (either from the atmosphere or from other sources) can undergo different biological and physio-chemical processes (Figure H-1a). The mercury cycle is a complex biogeochemical system involving both biotic and abiotic transformations of the different forms of mercury. Inorganic mercury species that are not reduced to form gaseous elemental mercury have an affinity for particulates and organic matter and thus will tend, if not re-emitted, to sink down to and accumulate in the sediments. The sediments of water bodies thus serve as both a sink and a reservoir for mercury contamination.

Although most inorganic mercury remains in this form in the sediments, a portion of that mercury can be converted to an organic form of mercury, methyl mercury. This conversion occurs primarily by metabolism within sulfate- and iron-reducing bacteria living in anaerobic sediments, i.e., sediments without oxygen (Fleming et al., 2006 and Jeremiason et al 2006). Mercury methylation generally cannot occur in aerobic (oxygenated) environments; in the water column it can occur only when conditions are anoxic (there is no oxygen). Methyl mercury production can occur not just in recently deposited surface sediments but also in much older, deeper sediments where the mercury was deposited decades previously, even though "old" inorganic mercury in sediments tends to be less biologically available than "new" inorganic mercury in sediments (Fleming et al., 2006; Axelrad et al., 2007). Methyl mercury from these deeper sediments can reach organisms living in shallower sediments by a process called diagenesis, which typically occurs in sediments with low organic carbon content. There is a depth beyond which, absent unusual disturbances, the mercury in the sediments will not reach animals or plants, but burial to such a depth is typically a slow process under natural conditions. As noted in the Florida study (FDEP, 2003) there is "slow mobilization of historically deposited mercury from deeper sediment layers to the water column. Until buried below the active zone, this mercury can continue to cycle through the system". Thus, even when emissions of inorganic mercury are reduced, there will be a substantial lag phase before emission reductions can result in reductions in methyl mercury concentrations in fish.

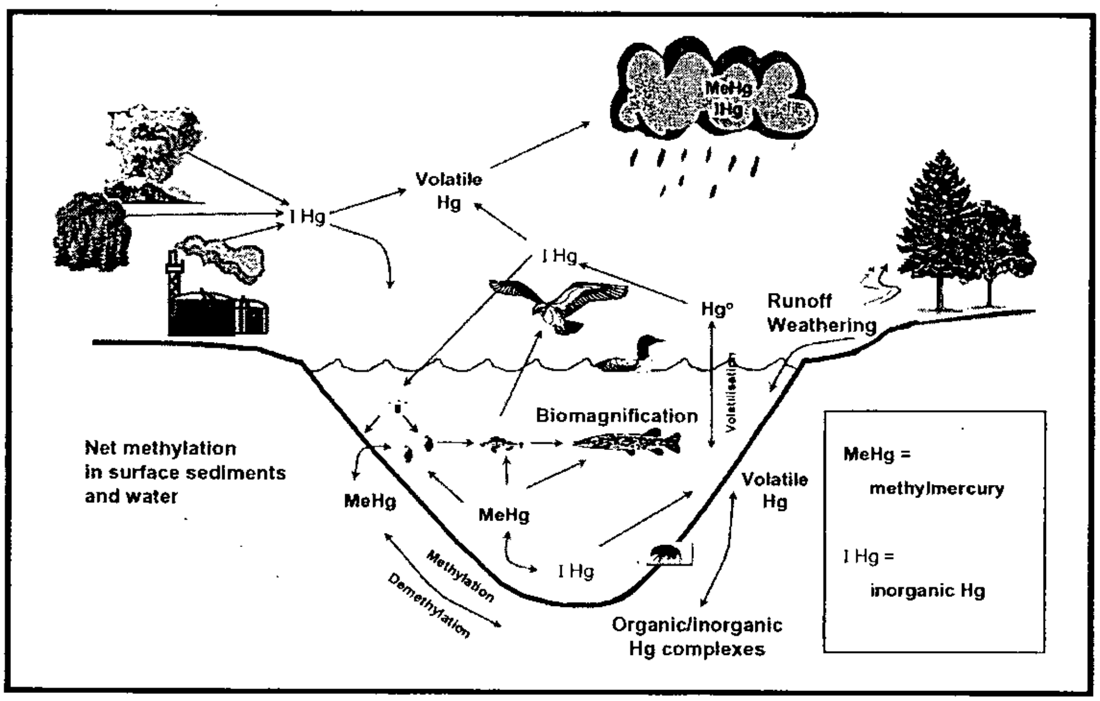


Figure-1a. The mercury cycle.

Production of methyl mercury in sediments is not a readily predictable process and can be highly variable between water bodies.

There is not a 1:1 relationship between inorganic mercury released to the atmosphere and deposited in water bodies and the level of methyl mercury found in water bodies and fish tissue. For instance, methyl mercury produced in water bodies from inorganic mercury deposition can be augmented by direct precipitation of methyl mercury from other sources, including: the atmosphere, runoff from land, or inputs from other water bodies such as wetlands (Eisler, 2006). Point source discharges continue to contribute mercury to water bodies.

Demethylation can occur in sediments (Figure H-1b), also mediated by naturally occurring microbes – possibly as a defense against mercury toxicity (Eisler, 2006). In most, but not all anaerobic systems, mercury methylation rates are greater than demethylation rates. However, methyl mercury concentrations and production rates vary more than do inorganic mercury deposition rates. For instance, a simple change in bacterial activity alone could "cause an increase in fish mercury concentrations even as atmospheric deposition [from industrial mercury emissions] decreases" (Mason et al., 2005). Thus there can be, for instance, freshwater systems containing relatively high concentrations of inorganic mercury but relatively low concentrations of methyl mercury because conditions are either less than optimum for mercury methylation, or demethylation is the predominant process. And the reverse can also occur. Thus, it is not surprising that in some cases waterbodies with the highest mercury concentrations are not the same waterbodies with the highest methyl mercury concentrations in fish.

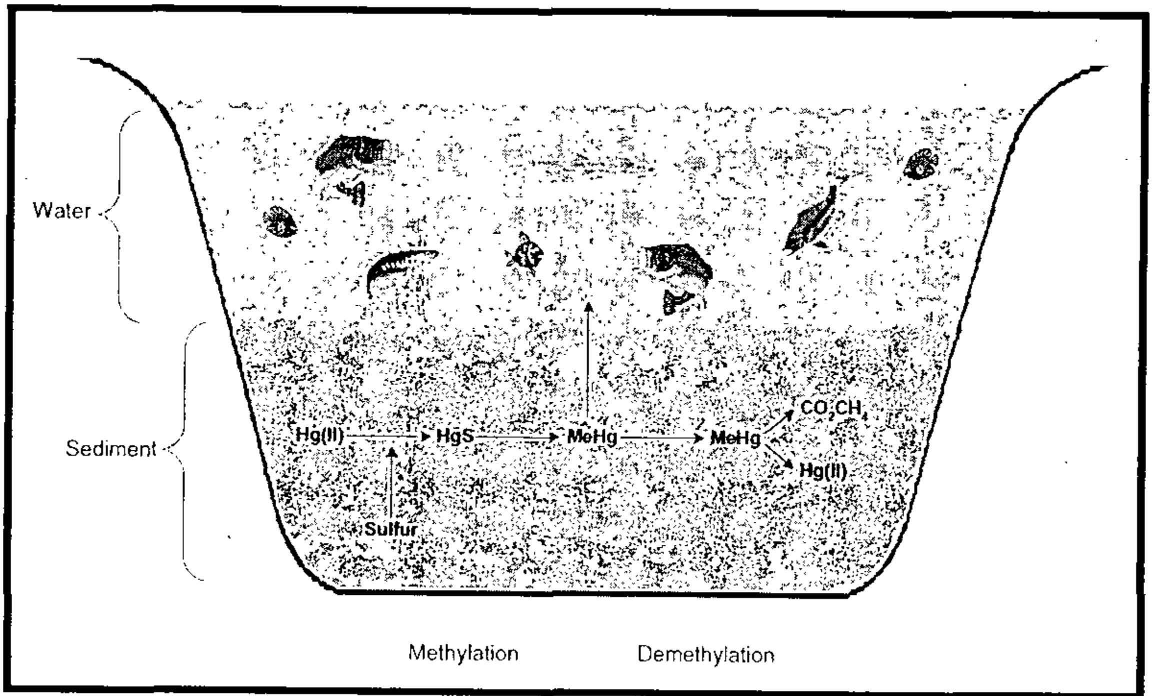


Figure 1b. Mercury Methylation

When the organic form of mercury, methyl mercury, is present in a water body, this organic form can biomagnify through food chains via the diet. Biomagnification is the process by which a few organic chemicals (methyl mercury is one) increase in concentrations through successive levels of the food chain as a result of dietary uptake. Fish absorb methyl mercury when they eat smaller aquatic organisms. Larger and older fish absorb more methyl mercury as they eat other fish. Aside from the concentrations of methyl mercury in the water body and sediment, which depend on the factors discussed above, the level of mercury contamination in fish can be affected by factors such as changing water levels (Sorensen et al, 2005) and dissolved organic matter (Ravichandran, 2004). Methyl mercury generally reaches the highest levels in predatory (piscivorous [fish-eating]) fish at the top of the aquatic food chain.

Mercury levels are also higher in older than in younger fish because older fish have had more time to accumulate higher levels of mercury. In fresh water environments piscivorous fish such as largemouth bass, found at the top of the food chain, tend to have the highest mercury levels in their tissues. Most of the mercury in fish is in the form of methyl mercury, which can be excreted, but more slowly than inorganic mercury. Thus, if fish are not exposed to new sources of methyl mercury in their diet they will begin to rid themselves of the methyl mercury in their bodies. This is not a fast process, but it does occur faster at higher temperatures than at lower temperatures (Eisler, 2006).

The most recent summary of information included in the South Florida Environmental Report (SFWMD, 2007) concludes that the Everglades is contaminated by sulfate originating in the EAA (Everglades Agricultural Area) (SFWMD, 2007). Based on sulfate concentration data, the study concludes that the Everglades contamination originates in the canals of the EAA. Sulfate concentrations are highest in the canals downstream of the EAA and are lowest in the marsh areas of the south. Sulfate concentrations observed in rainwater indicated concentrations too low to account for the observed sulfate concentrations at a northern marsh. While the study suggests the determination of a sulfur mass balance for the Everglades, sulfur is used as a soil supplement in the EAA and the observed sulfate highest concentrations are located near canals near the EAA.

Atmospheric Deposition

Atmospheric deposition of mercury has been evaluated in numerous studies including the Florida Atmospheric Mercury Study (FAMS) and the National Atmospheric Deposition Program's Mercury Deposition Network (NADP, MDN). In addition, to monitoring data, studies have been performed to evaluate the sources of mercury deposition. The latest studies suggest about 21 percent contribution from local sources, with ranges from 8 to 17 percent for more recent periods. Up to 80 percent have been estimated for areas between the urban fringe and the Everglades in the mid 1990's timeframe.

The potential mercury deposition predicted for the Project at the Everglades National Park was estimated using the CALPUFF model and assumptions based on EPA as presented in the "Mercury Study Report to Congress, Volume III: Fate and Transport of Mercury in the Environment", December 1997. In this analysis, mercury was assumed to be emitted as elemental mercury [Hg(0)], reactive gas mercury [Hg(+2)], and particulate mercury [Hg(p)]. Based on the proposed emission controls, the total mercury emissions from FGPP were assumed to be emitted as 95 percent as Hg(0), 4.5 percent as Hg(+2), and 0.5 percent as Hg(p). Both wet deposition and dry deposition of mercury were included in the modeling. For wet deposition, Hg(+2) has a high solubility in water and is readily incorporated into precipitation. Hg(0) has a low solubility and does not tend to accumulate in rain to the degree as the other two types of mercury. For dry deposition, Hg(+2) deposits at a higher rate per unit mass than Hg(p) or Hg(0) due to its higher chemical reactivity with particulate surfaces. Based on EPA assumptions, dry deposition of Hg(0) was assumed to be minimal and, therefore, not modeled, since Hg(0) does not exhibit a net dry depositional flux to vegetation until the atmospheric concentration exceeds a value well above the background concentration of 1.6 nanograms per cubic meter (ng/m^3). In these analyses, no transformation of the mercury species to other species was assumed.

The results of these analyses for the 3 years of CALPUFF meteorological data from 2001 to 2003 are summarized in Table FDEP H-1B. As shown, the average mercury deposition due to the Project for the 3 years over the Everglades National Park is estimated to be 3.7×10^{-9} grams per square meter per year ($g/m^2/yr$) or 0.0037 micrograms per square meter per year ($\mu g/m^2/yr$. In contrast, the observed mercury from wet deposition at the MDN ENP site ranged from 17.9 to 26.8 $\mu g/m^2/yr$ for the years 2001 through 2005 with an average of 19.9 $\mu g/m^2/yr$. The predicted mercury deposition in the Everglades National Park is over 4 thousand times lower than the observed concentrations.

The maximum sulfur deposition predicted in the Everglades National Park (ENP) from FGPP ranged from 0.012 kg/ha/yr to 0.02 kg/ha/yr, as presented in Table 7-9 of the Air Construction/PSD Permit Application. As discussed in the application, sulfur deposition occurs as a result of both anthropogenic and natural sources. Sulfur deposition occurs naturally due to the component of sea salt. In addition, anthropogenic and other natural sources contribute to sulfur deposition in the everglades. Two major studies determined the sulfur deposition in southern Florida that included stations in and near the ENP. These studies were the Florida Acid Deposition Study (FADS) which monitored sulfur deposition during the period October 1981 through September 1984. Both wet and dry deposition, as well as particulate and SO_2 deposition, were determined. The Florida Atmospheric Mercury Study (FAMS) in addition to monitoring aerosol and total mercury, measured major ions including sulfur during the period of May 1993 through December 1996. One site for each research project was located at or near the Tamiami Trail Ranger Station. A comparison of the maximum sulfur deposition predicted from FGPP and the data available from FADS (Station 13) and FAMS (Station TT) is shown in the table that follows.

FGPP (Predicted)	2001	0.012	kg S/ha/yr
	2002	0.02	kg S/ha/yr
	2003	0.014	kg S/ha/yr
FADS (Oct 81-Sept 84):	Total (w/SO_2)	4.896	kg S/ha/yr
	Total Wet and Dry	4.370	kg S/ha/yr
	Sea Salt Contribution	0.716	kg S/ha/yr
FAMS (May 93-Dec 96):	Total Wet	4.043	kg S/ha/yr
	Sea Salt Contribution	0.704	kg S/ha/yr
FGPP Maximum as Percent of:	FADS-Total (w/SO_2)	0.41%	
	FADS- Total Wet and Dry	0.46%	
	Sea Salt Contribution	2.79%	
	FAMS-Total Wet	0.49%	
	FAMS-Sea Salt Contribution	2.84%	

As shown, the sulfur deposition observed in the FADS and the FAMS are very similar. Both the total and sea salt sulfur deposition in kg/ha/yr are similar even though the monitoring periods were separated by about 10 years. As shown, the maximum FGPP contribution is over 200 times less than the total atmospheric sulfur deposition and 35 times less than the contribution from sea salt. The sea salt contribution to wet deposition in the Everglades NP was determined in FADS to be about 15 percent. The sea salt contribution observed during FAMS was about 17 percent. The contribution from sea salt is naturally occurring and will not change.

The SO_2 emissions in the region have also decreased significantly in the last 6-years with the repowering of the FPL Fort Myers Plant. Two units firing only residual oil were repowered using six highly efficient combustion turbines firing only natural gas. This project began in 1998 with full operation in 2001. A total emissions reduction of approximately 20,000 tons of SO_2 per year was realized from this repowering project. The significance of this reduction is that the FPL Fort Myers plant is approximately the same distance as FGPP from the ENP and their location would be influenced by similar meteorology (i.e., northerly winds). The SO_2 reduction realized from the FPL Fort Myers Repowering Project is about 7 times higher than the potential SO_2 emissions from FGPP. Moreover, the emission rates for the retired Fort Myers units were over 50 times higher than that proposed for FGPP.

The FDEP has adopted rules as part of Chapters 62-204, 62-210 and 62-296 F.A.C. to implement EPA's Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). These rules set forth a program where significant potential reductions in sulfur dioxide and mercury will occur within Florida and nationwide. Based on the FDEP's rules and EPA's projections, the statewide reduction in implementing CAIR from SO_2 emissions in 2003 is 221,550 tons per year (TPY) in 2010 with the implementation of CAIR Phase I cap and 257,000 TPY based on EPA's projections. By 2015 and beyond the reductions from 2003 are 297,585 TPY under the CAIR Phase II cap and 308,000 TPY as projected by EPA. The significance of these reductions is that sulfate contribution to southern Florida will be reduced by these rules.

Similar to CAIR, reductions in mercury will occur with the FDEP implementation of CAMR. The FDEP adopted a hybrid CAMR that limits the mercury cap under Phase I to 70 percent of the EPA allocation of 2,464 pounds/year starting in the year 2010. The Phase II mercury cap would be 974 pounds per year with a 5 percent new source set aside for 2018 and beyond. FDEP projects reductions from mercury emissions in 1999 of 890 pounds/year for the period 2010 through 2017.

Taking together the low deposition of mercury and sulfur from FGPP, the existing contributions of both anthropogenic and natural sulfur deposition, regional reduction in sulfur emissions and implementation of CAIR and CAMR, the potential impacts of FGPP to mercury and sulfur levels in the ENP are insignificant.

FPL's Environmental Commitment

As indicated above, neither the mercury nor the sulfate deposition from the FGPP will pose a significant ecological impact on the ENP. The FGPP project is designed with maximum boiler efficiency and with state of the art, sulfur and mercury controls. FPL has proposed the lowest BACT limits in the nation for SO_2 for this project.

FPL's fleet has greatly reduced sulfur emissions over the past 15 years. FPL has undertaken repowering projects at the Lauderdale, Sanford and Fort Myers which have resulted in significant emission reductions of all air pollutants, especially sulfur. The repowering at the Fort Myers facility alone resulted in a total net reduction of approximately 20,000 tons of SO_2 (seven times the proposed emissions from FGPP). Total net reductions of sulfur emissions from the Sanford facility were approximately 23,000 TPY. FPL has further reduced sulfur emissions by burning 1 percent fuel oil at our oil burning facilities such as Turkey Point and Port Everglades. FPL has added natural gas-burning capabilities to the oil burning plants which provide fuel diversity while further reducing emissions.

FPL fully recognizes the importance of the Everglades ecosystem and of the national parks and wildlife refuges in the region. In addition to the project design and the associated environmental protections, FPL will investigate opportunities in Florida to:

- Optimize mercury controls on the FGPP and consider a lower emission rate once it is demonstrated that lower rates are achievable.
- Undertake design and implementation of a mercury study that would further enhance the understanding of bioaccumulation of mercury in fish and wildlife.
- Investigate opportunities for further mercury reductions in the state of Florida targeting reductions in mercury deposition in ENP.

Once these and other mitigation opportunities are fully analyzed, FPL will discuss them with the NPS and FDEP. FPL commits to implement the selected program(s) prior to operation of the plant to ensure mercury methylation and bio-accumulation potential in Everglades National Park is minimized.

FDEP-1C. Threatened and Endangered Species Concerns: We are also concerned about the potential effects of GPP emissions on threatened and endangered plants and wildlife protected by the Federal Endangered Species Act. Information regarding threatened and endangered species effects will be pertinent to federal actions or approvals needed before GPP is permitted or commences construction. In order to avoid delays, it may be prudent for FPL to examine potential effects on threatened and endangered species as soon as practical.

RESPONSE: Issuance of an Air Construction/PSD permit by FDEP is not a federal action. However, FPL is entering into discussions with the FDEP and the USFWS regarding potential impacts on threatened and endangered plants and wildlife protected by the Federal Endangered Species Act.

FDEP-1D: Best Available Control Technology (BACT): Because the short-term (3-hour and 24-hour average) emissions rates are not specified for SO_2 and NO_x, and the averaging period for H_2SO_4 is not identified, we can not properly compare the level of emission control (BACT analysis) to similar facilities that do have appropriate short-term limits. We ask FPL to provide this information in its permit application.

RESPONSE: The emissions rates, as discussed in the response to FDEP H-1A, for NO_x and SO_2 and provided in the original Air Permit/PSD Application are 24-hour averages. The 24-hour emission rates were based on 0.05 and 0.04 lb/MMBtu for NO_x and SO_2, respectively. The 3-hour emission rate for NO_x and SO_2 is based on 0.065 lb/MMBtu, as discussed in the response to FDEP H-1A.

TABLE FDEP-1A.1a
SUMMARY OF SO_2 EMITTING FACILITIES INCLUDED IN THE PSD CLASS I INCREMENT CONSUMPTION ANALYSIS AT THE CHASSAHOWITZKA NWA FOR FPL GLADES POWER PARK

Plant ID	Facility Name	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Chassahowitzka NWA[a] X (km)	Y (km)	Direction (deg.)	Distance (km)	Maximum SO_2 Emissions (TPY)[c]
	FL Mining and Materials Kiln		356.2	3,169.9	18.4	-5.3	106.1	19.1	50
0530010	Cemex	Hernando	357.5	3169.2	19.7	-6.0	107	20.6	132
	Oman Construction		359.8	3,164.9	22.0	-10.3	115.1	24.3	73
	Forest Meadows Funeral Home, Inc.		361.4	3,168.4	23.6	-6.8	106.1	24.6	78
	Asphalt Pavers 3		359.9	3,162.4	22.1	-12.8	120.1	25.5	78
0530021	FL Crushed Stone Kiln 1	Hernando	360.0	3,162.5	22.2	-12.7	119.8	25.6	3,532
0170004	Crystal River Power Plant	Citrus	334.3	3204.5	-3.5	29.3	353	29.5	70,136 -75,538
	Hospital Corp of America		333.4	3,141.0	-4.4	-34.2	187.3	34.5	6
1010373	Shady Hills Generating Station	Pasco	347.0	3139.0	9.2	-36.2	166	37.4	332
1010056	Pasco County Resource Recovery Facility	Pasco	348.6	3139.0	10.8	-36.2	163	37.8	490
	FDOC Boiler #3		382.2	3,166.1	44.4	-9.1	101.6	45.3	104
	New Pt Richey Hospital		331.2	3,124.5	-6.6	-50.7	187.4	51.1	3
0530017	E.R. Jahna Industries, Inc.		386.7	3,155.8	48.9	-19.4	111.6	52.6	29
1010017	Anclote Power Plant	Pasco	327.4	3120.7	-10.4	-54.5	191	55.5	120,811
	Couch Const-Odessa (Asphalt)		340.7	3,119.5	2.9	-55.7	177.0	55.8	252
	Dris Paving (Asphalt)	Pasco	340.6	3,119.2	2.8	-56.0	177.1	56.1	8
	Stauffer (Shutdown)	Pinellas	325.6	3,116.7	-12.2	-58.5	191.8	59.8	-2,263
1010071	Pasco Cogen Limited	Pasco	385.6	3,139.0	47.8	-36.2	127.1	60.0	175
0690032	Asphalt Production Llc	Lake	407.1	3,180.9	69.3	5.7	85.3	69.5	76
	Couch Const-Zephyrhills (Asphalt)		390.3	3,129.4	52.5	-45.8	131.1	69.7	123
0830001	COUNTS CONSTRUCTION COMPANY, INC.		385.9	3,231.4	48.1	56.2	40.6	74.0	21
	Yuengling Brewing Co.		362.0	3,103.2	24.2	-72.0	161.4	76.0	39
0570005	CF Industries--Plant City	Hillsborough	388.0	3116.0	50.2	-59.2	140	77.6	6,741
0830059	STEVEN COUNTS, INC. FKA HARLIS ELLINGTON		385.2	3,237.5	47.4	62.3	37.3	78.3	17
0570003	CF Industries, Inc. - Bartow	Hillsborough	362.8	3,098.4	25.0	-76.8	162.0	80.8	1,826
0570089	Tampa Bay Shipbuilding & Repair Co.	Hillsborough	353.3	3,095.9	15.5	-79.3	168.9	80.8	12
0570127	Mckay Bay Refuse-To-Energy Facility	Hillsborough	360.2	3092.2	22.4	-83.0	165	86.0	716
7775053	E.R. Jahna Industries, Inc.		363.6	3,092.3	25.8	-82.9	162.7	86.9	29
	General Portland Cement #4 and #5		358.0	3,090.6	20.2	-84.6	166.6	87.0	-4,599

TABLE FDEP-1A.1a
SUMMARY OF SO_2 EMITTING FACILITIES INCLUDED IN THE PSD CLASS I INCREMENT CONSUMPTION ANALYSIS AT THE CHASSAHOWITZKA NWA FOR FPL GLADES POWER PARK

Plant ID	Facility Name	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Chassahowitzka NWA[a] X (km)	Y (km)	Direction (deg.)	Distance (km)	Maximum SO_2 Emissions (TPY)[a]
0570261	Hillsborough Cty. RRF	Hillsborough	368.2	3092.7	30.4	-82.5	160	87.9	771
1030117	Pinellas Co. Resource Recovery Facility	Pinellas	335.2	3084.1	-2.6	-91.1	182	91.1	3,044
0570008	Mosaic Fertilizer - Riverview	Hillsborough	362.9	3,082.5	25.1	-92.7	164.8	96.0	6,553
									-42,605
0690039	C A Meyer Paving & Const Co	Lake	433.6	3,158.3	95.8	-16.9	100.0	97.3	48
0694801	Lake Cogen	Lake	434.0	3,198.8	96.2	23.6	76.2	99.1	175
1050004	C.D. Mcintosh, Jr. Power Plant	Polk	409.0	3106.2	71.2	-69.0	134	99.1	19,687
	Borden Polk		414.5	3,109.0	76.7	-66.2	130.8	101.3	-184
1050003	Lakeland Electric, Larsen Power Plant	Polk	408.9	3102.5	71.1	-72.7	136	101.7	926
	Big Bend Transfer Co. L.L.C.		361.1	3,076.2	23.3	-99.0	166.8	101.7	16
0570039	TECO, Big Bend Station	Hillsborough	361.9	3075.0	24.1	-100.2	166	103.1	15,663
									-254,040
0571242	National Gypsum - Apollo Beach	Hillsborough	364.7	3,075.6	26.9	-99.6	164.9	103.1	238
1050047	Agrifos Mining, L.L.C. - Nichols	Polk	398.7	3,085.3	60.9	-89.9	146	108.6	2,219
	Ridge Cogeneration		416.7	3,100.4	78.9	-74.8	133.5	108.7	480
1050057	Mosaic Fertilizer, Nichols Plant	Polk	398.4	3,084.2	60.6	-91.0	146	109.3	-2,029
1050334	Auburndale Power Osprey	Polk	420.8	3,103.3	83.0	-71.9	130.9	109.8	598
1050023	Cutrale Citrus Juices Usa,Inc	Polk	421.6	3,103.7	83.8	-71.5	130.5	110.2	1,677
0950111	Walt Disney World Company	Orange	442.0	3,139.0	104.2	-36.2	109.2	110.3	127
0010087	Thompson S. Baker Cement Plant	Alachua	348.4	3287.0	10.6	111.8	5	112.3	78
1050059	Mosaic Fertilizer - New Wales	Polk	396.7	3,079.4	58.9	-95.8	148.4	112.5	14,625
									-6,267
1050048	Cargill Mulberry (Formerly Mulberry Phosphates, Inc.)	Polk	406.8	3,085.1	69.0	-90.1	142.6	113.5	-9,278
1050090	Todhunter International Inc.	Polk	429.6	3,108.0	91.8	-67.2	126.2	113.7	17
1050046	Mosaic Fertilizer - Bartow	Polk	409.8	3,086.6	72.0	-88.6	140.9	114.2	6,754
1050050	US Agri-Chem Bartow	Polk	413.2	3,086.3	75.4	-88.9	139.7	116.6	-1,579
	IMC - Agrico Pierce		404.1	3,079.0	66.3	-96.2	145.4	116.8	-1,645
	Mobil Electrophos Division		405.6	3,079.4	67.8	-95.8	144.7	117.4	-3,334
1050053	Mosaic Fertilizer - Green Bay	Polk	409.5	3,080.1	71.7	-95.1	143.0	119.1	6,895

TABLE FDEP-1A.1a
SUMMARY OF SO_2 EMITTING FACILITIES INCLUDED IN THE PSD CLASS I INCREMENT CONSUMPTION ANALYSIS AT THE CHASSAHOWITZKA NWA FOR FPL GLADES POWER PARK

Plant ID	Facility Name	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Chassahowitzka NWA[a] X (km)	Relative to Chassahowitzka NWA[a] Y (km)	Direction (deg.)	Distance (km)	Maximum SO_2 Emissions (TPY)[c]
0970014	Progress Energy- Intercession City Plant	Osceola	446.3	3126.0	108.5	-49.2	114	119.1	17,026
0970043	Kissimmee Utilities - Cane Island	Osceola	447.7	3,127.9	109.9	-47.3	113.3	119.6	16,213
	Borden Hillsborough		394.6	3,069.6	56.8	-105.6	151.7	119.9	-225
0010006	Deerhaven Generating Station	Alachua	365.7	3292.6	27.9	117.4	13	120.7	12,995
1050217	Polk Power Partners - Mulberry Cogen Facility	Polk	413.6	3080.6	75.8	-94.6	141	121.2	464
	Mosaic Fertilizer - South Pierce		407.5	3,071.4	69.7	-103.8	146.1	125.0	3,942
	Estech/Swift Polk		411.5	3,074.2	73.7	-101.0	143.9	125.0	-4,853
	Imperial Phosphates (Brewer)		404.8	3,069.5	67.0	-105.7	147.6	125.1	-670
	Dolime		404.8	3,069.5	67.0	-105.7	147.6	125.1	-355
1050233	TECO, Polk Power Station	Polk	402.5	3067.4	64.7	-107.9	149	125.7	2,926
1050234	PE Hines Energy Complex	Polk	414.3	3,073.9	76.5	-101.3	142.9	126.9	859
0970001	Kissimmee Utility Authority--Hansel Plant	Osceola	460.1	3,129.3	122.3	-45.9	110.6	130.6	1,116
1270028	FPC - Debary Facility	Volusia	467.5	3197.2	129.7	22.0	80	131.6	16,213
1050051	U.S. Agri-Chemicals - Ft. Meade	Polk	416.0	3,069.0	78.2	-106.2	143.6	131.9	4,383
0490015	Hardee Power Partners,Ltd	Hardee	404.8	3,057.4	67.0	-117.8	150.4	135.5	9,673
	Suwannee American Cement		321.4	3,315.9	-16.4	140.7	353.4	141.7	124
1070005	Georgia-Pacific Corp. Pulp/Paper Mill	Putnam	434.0	3283.4	96.2	108.2	42	144.8	31,939
	Florida Power & Light - Palatka		442.8	3,277.6	105.0	102.4	45.7	146.7	-8,935
1070014	Florida Power & Light - Putnam Plant	Putnam	443.3	3,277.6	105.5	102.4	45.9	147.0	4,053
0950137	Orlando Utilities Commission - Stanton	Orange	483.5	3,150.6	145.7	-24.6	99.6	147.8	24,083
0190007	Iluka Resources Inc.	Clay	432.4	3,304.2	94.6	129.0	36.3	160.0	246
0310496	Nas Cecil Field	Duval	414.4	3,343.9	76.6	168.7	24.4	185.3	141
	Gerdau Ameristeel		405.7	3,350.0	67.9	174.8	21.2	187.5	141
	JEA Brandy Branch		408.8	3,354.5	71.0	179.3	21.6	192.8	-99 430
	PCS		328.3	3,368.8	-9.5	193.6	357.2	193.8	-13,213 10,000

[a] The approximate center of the Chassahowitzka NWA is located at UTM Coordinates: East 337.8 km, North 3175.2 km

TABLE FDEP-1A.1b
SUMMARY OF SO_2 SOURCES INCLUDED IN THE AIR MODELING FOR THE PSD CLASS I INCREMENT CONSUMPTION ANALYSES AT THE CHASSAHOWITZKA NWA
FPL GLADES POWER PARK

Facility ID	Facility Name / Emission Unit Description	EU ID	CALPUFF ID Name	UTM Location X (m)	UTM Location Y (m)	LCC Location X (km)	LCC Location Y (km)	Stack Parameters Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (g/sec)	PSD Source?[a] (EXP/CON)	Modeled PSD Source?
	FL Mining and Materials Kiln																		
			FMM	356,200	3,169,900	1426.268	-1146.928	105	32.00	14	4.27	250	394	32.5	9.91	11.51	1.45	CON	Yes
0530010	CEMEX																		
	Cement Kiln No. 1	3	CEMEX3	357,470	3,169,190	1427.654	-1147.418	150	45.72	13.0	4.0	285	414	34.0	10.4	16.5	2.08	NO	No
	Cement Kiln No. 2	14	CEMEX14	357,470	3,169,190	1427.654	-1147.418	105	32.00	14.0	4.3	250	394	32.0	9.8	16.5	2.08	CON	Yes
	Oman Construction																		
			OMAN	359,800	3,164,900	1430.714	-1151.300	25	7.62	6.0	1.83	165	347	20.6	6.28	16.59	2.09	CON	Yes
0010057	Forest Meadows Funeral Home																		
	Cremator To Burn Human Remains & Appropriate Containers	1	FMFH1	371,400	3,283,500	1421.558	-1030.713	15	4.57	1.7	0.52	1147	893	23.0	7.01	0.80	0.10	CON	Yes
	Asphalt Pavers 3																		
			ASPHALT3	359,900	3,162,400	1431.545	-1153.781	40	12.19	4.5	1.37	219	377	34.7	10.58	17.86	2.25	CON	Yes
0530021	Florida Crushed Stone Co., Inc																		
	POWER PLANT	18	FCRUSH18	361,340	3,162,370	1432.684	-1153.561	320	97.54	16.0	4.88	300	422	69.6	21.21	770.0	97.02	CON	Yes
	BCP: Kiln, Clinker Cooler, Raw Mill, & Dryer with Baghouse	20	FCRUSH20	361,340	3,162,370	1432.684	-1153.561	300	91.44	16.0	4.88	220	378	47.0	14.33	50.0	6.30	CON	Yes
	KILN #2 SYSTEM: preheater/precalciner, cooler,dyer,raw mill	44	FCRUSH44	361,340	3,162,370	1432.684	-1153.561	320	97.54	14.0	4.27	258	399	33.8	10.30	28.8	3.63	CON	Yes
0170004	Crystal River Power Plant																		
	Fossil Fuel Steam Generator Unit 1 (Phase II Acid Rain Unit)	1	CRYRIV1B	334,300	3,204,500	1398.522	-1116.163	499	152.1	15	4.57	300	422	138.1	42.1	-2492.06	-314.00	EXP	Yes
	Fossil Fuel Steam Generator Unit 2 (Phase II Acid Rain Unit)	2	CRYRIV2B	334,300	3,204,500	1398.522	-1116.163	502	153.0	16	4.88	300	422	138.1	42.1	-14753.97	-1859.00	EXP	Yes
			CRYRIV12	334,300	3,204,500	1398.522	-1116.163	499	152.1	15	4.57	300	422	138.1	42.1	-17246.03	-2173.00	EXP	Yes
	Fossil Fuel Steam Generator-5 (Phase I & II Acid Rain Unit)	3	CRYRIV3B	334,300	3,204,500	1398.522	-1116.163	585	178.3	25.5	7.77	253	396	68.9	21.0	8006.35	1008.80	CON	Yes
	Fossil Fuel Steam Generator-4 (Phase I & II Acid Rain Unit)	4	CRYRIV4B	334,300	3,204,500	1398.522	-1116.163	585	178.3	25.5	7.77	253	396	68.9	21.0	8006.35	1008.80	CON	Yes
			CRYRIV34	334,300	3,204,500	1398.522	-1116.163	585	178.3	25.5	7.77	253	396	68.9	21.0	16012.7	2017.60	CON	Yes
	Hospital Corp of America																		
	Boiler #1		HCOA1	333400	3141000	1408.614	-1179.743	36	11.0	1	0.30	500	533	13.1	3.99	0.63	0.08	CON	Yes
	Boiler #2		HCOA2	333400	3141000	1408.614	-1179.743	36	11.0	1	0.30	500	533	13.1	3.99	0.63	0.08	CON	Yes
			HCOA	333400	3141000	1408.614	-1179.743	36	11.0	1	0.30	500	533	13.1	3.99	1.26	0.16	CON	Yes
1010373	Shady Hills Generating Station																		
	Simple Cycle CTs No. 1-3		IPSPASCO	347,000	3,139,000	1422.485	-1179.397	60	18.3	22	6.7	1076	853	122.0	37.2	304.5	38.37	CON	Yes
1010056	Pasco County Resource Recovery Facility																		
	Municipal Waste Combustor Unit #1	1	PASCRRF1	348,620	3,139,020	1424.093	-1179.097	275	83.8	4.7	1.4	250	394	81.9	25.0	15.05	1.90	CON	Yes
	Municipal Waste Combustor Unit #2	2	PASCRRF2	348,620	3,139,020	1424.093	-1179.097	275	83.8	4.7	1.4	250	394	81.9	25.0	15.05	1.90	CON	Yes
	Municipal Waste Combustor Unit #3	3	PASCRRF3	348,620	3,139,020	1424.093	-1179.097	275	83.8	4.7	1.4	250	394	81.9	25.0	15.05	1.90	CON	Yes
			PASCRRF	348,620	3,139,020	1424.093	-1179.097	275	83.8	4.7	1.4	250	394	81.9	25.0	45.15	5.69	CON	Yes
	FDOC																		
	Boiler No. 3		FDOC	382,200	3,166,100	1452.765	-1146.220	30	9.1	2.0	0.6	401	478	15	4.6	23.73	2.99	CON	Yes
	New Pt Richey Hospital																		
	Boiler #1		NEWPTR1	331,200	3,124,500	1409.280	-1196.621	36	11.0	1.0	0.3	520	544	12.7	3.9	0.48	0.06	CON	Yes
	Boiler #2		NEWPTR2	331,200	3,124,500	1409.280	-1196.621	36	11.0	1.0	0.3	520	544	12.7	3.9	0.24	0.03	CON	Yes
			NEWPTR	331,200	3,124,500	1409.280	-1196.621	36	11.0	1.0	0.3	520	544	12.7	3.9	0.72	0.09	CON	Yes
0530017	E.R. Jahna Industries, Inc.																		
	Limerock Dryer		ERJAHNA	386,700	3,155,800	1459.034	-1155.729	35	30	6.0	30	129	327	29.5	30	6.51	0.82	CON	Yes

TABLE FDEP-1A.1b

SUMMARY OF SO_2 SOURCES INCLUDED IN THE AIR MODELING FOR THE PSD CLASS I INCREMENT CONSUMPTION ANALYSES AT THE CHASSAHOWITZKA NWA

FPL GLADES POWER PARK

Facility ID	Facility Name / Emission Unit Description	EU ID	CALPUFF ID Name	UTM Location X (m)	UTM Location Y (m)	LCC Location X (km)	LCC Location Y (km)	Stack Height ft	Stack Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (g/sec)	PSD Source? ª (EXP/CON)	Modeled PSD Source?
1010017	Anclote Power Plant																		
	Steam Turbine Gen Anclote Unit No 1	1	FPCANC1	327,410	3,120,680	1406.170	-1201.095	499	152.1	24.0	7.3	320	433	62	18.9	13950.8	1757.79	NO	No
	Steam Turbine Gen Anclote Unit No 2	2	FPCANC2	327,410	3,120,680	1406.170	-1201.095	499	152.1	24.0	7.3	320	433	62	18.9	13631.8	1717.60	NO	No
	Couch Const-Odessa (Asphalt)																		
			COUCHODE	340,700	3,119,500	1419.599	-1199.985	30	9.1	4.6	1.4	325	436	73.2	22.3	57.54	7.25	CON	Yes
	Dris Paving (Asphalt)																		
			DRIS	340,600	3,119,200	1419.551	-1200.303	40	12.2	10	3.0	151	339	21.2	6.5	1.83	0.23	CON	Yes
	Stauffer (Shutdown)																		
			STAUFR1	325,600	3,116,700	1405.057	-1205.388	24	7.3	3	0.9	376	464	10.6	3.2	-38.57	-4.86	EXP	Yes
			STAUFR2	325,600	3,116,700	1405.057	-1205.388	60	18.3	2.3	0.7	120	322	75.0	22.9	-11.9	-1.50	EXP	Yes
			STAUFR3	325,600	3,116,700	1405.057	-1205.388	161	49.1	3.9	1.2	143	335	11.8	3.6	-404.21	-50.93	EXP	Yes
			STAUFR4	325,600	3,116,700	1405.057	-1205.388	84	25.6	7	2.1	91	306	22.9	7.0	-58.41	-7.36	EXP	Yes
			STAUFR5	325,600	3,116,700	1405.057	-1205.388	84	25.6	3	0.9	120	322	22.9	7.0	-3.57	-0.45	EXP	Yes
1010071	Pasco Cogen Limited																		
	Combustion Turbine Units 1 and 2		PASCOGN	385,600	3,139,000	1460.872	-1172.711	100	30.5	11	3.4	232	384	56.2	17.1	87.5	11.03	CON	Yes
0690032	Asphalt Production LLC																		
	ASPHALT BATCH PLANT	1	ABP1	408,110	3,180,780	1475.940	-1127.054	25	7.6	7.5	2.3	165	347	15	4.6	17.35	2.19	CON	Yes
	Couch Const-Zephyrhills (Asphalt)																		
			COUCHZEP	390,300	3,129,400	1467.223	-1181.493	20	6.1	4.5	1.4	300	422	68.9	21.0	28.1	3.54	CON	Yes
0830001	Counts Construction Company, LLC																		
	ASPHALT BATCH PLANT DRYER	1	CCC1	385,900	3,231,400	1445.053	-1080.410	35	10.7	2.5	0.8	300	422	142	43.3	13.15	1.66	CON	Yes
0570006	Yuengling Brewing Co																		
	2 Natural gas boilers	1	YNGBREW1	362,000	3,103,200	1443.629	-1212.614	90	27.4	6.5	2.0	275	408	7.0	2.1	9	1.13	CON	Yes
0570005	CF Industries - Plant City																		
	"A" SAP	2	SAPA	388,000	3,116,000	1467.276	-1195.295	110	33.5	5.0	1.52	83	301	68.7	20.9	303.3	69.2	CON	Yes
	"B" SAP	3	SAPB	388,000	3,116,000	1467.276	-1195.295	110	33.5	5.0	1.52	83	301	74.8	22.8	303.3	69.2	CON	Yes
			SAPA&B	388,000	3,116,000	1467.276	-1195.295	110	33.5	5.0	1.52	83	301	68.7	20.9	606.6	138.5	CON	Yes
	"C" SAP	7	SAPC	388,000	3,116,000	1467.276	-1195.295	199	60.7	8.0	2.44	158	343	46.7	14.2	401.0	91.6	CON	Yes
	"D" SAP	8	SAPD	388,000	3,116,000	1467.276	-1195.295	199	60.7	8.0	2.44	161	345	48.3	14.7	401.0	91.6	CON	Yes
			SAPC&D	388,000	3,116,000	1467.276	-1195.295	199	60.7	8.0	2.44	158	343	46.7	14.2	802.0	183.1	CON	Yes
	"A" Dap/Map Plant	10	ADMP	388,000	3,116,000	1467.276	-1195.295	99	30.2	10.0	3.05	137	331	36.8	11.2	23.5	5.4	CON	Yes
	"Z" Dap/Map Plant	11	ZDMP	388,000	3,116,000	1467.276	-1195.295	180	54.9	9.0	2.74	140	333	44.5	13.6	104.6	23.9	CON	Yes
	"X" Dap/Map Plant	12	XDMP	388,000	3,116,000	1467.276	-1195.295	180	54.9	9.0	2.74	134	330	50.7	15.5	104.6	23.9	CON	Yes
	"Y" Dap/Map Plant	13	YDMP	388,000	3,116,000	1467.276	-1195.295	180	54.9	9.0	2.74	135	330	53.3	16.2	104.6	23.9	CON	Yes
			XYZDMP	388,000	3,116,000	1467.276	-1195.295	180	54.9	9.0	2.74	140	333	44.5	13.6	313.8	71.6	CON	Yes
0570089	Tampa Bay Shipbuilding & Repair Co.																		
	DIESEL COMPRESSORS	5	TBSHIP5	358000	3089000	1442.115	-1227.521	10	3.0	0.5	0.2	350	450	148.5	45.3	2.74	0.35	CON	Yes
0570127	McKay Bay Refuse-To-Energy Facility																		
	MWC & Aux Burner No. 1		MBREF1	360,200	3,092,200	1443.750	-1223.937	201	61.3	4.2	1.3	289	416	73.3	22.3	40.87	5.15	CON	Yes
	MWC & Aux Burner No. 2		MBREF2	360,200	3,092,200	1443.750	-1223.937	201	61.3	4.2	1.3	289	416	73.3	22.3	40.87	5.15	CON	Yes
	MWC & Aux Burner No. 3		MBREF3	360,200	3,092,200	1443.750	-1223.937	201	61.3	4.2	1.3	289	416	73.3	22.3	40.87	5.15	CON	Yes
	MWC & Aux Burner No. 4		MBREF4	360,200	3,092,200	1443.750	-1223.937	201	61.3	4.2	1.3	289	416	73.3	22.3	40.87	5.15	CON	Yes
			MBREF	360,200	3,092,200	1443.750	-1223.937	201	61.3	4.2	1.3	289	416	73.3	22.3	163.48	20.60	CON	Yes
	General Portland Cement #4																		
			GPCEM4B	358,000	3,090,600	1441.837	-1225.919	118	36.0	9	2.7	450	505	57.8	17.6	-499.92	-62.99	EXP	Yes
	General Portland Cement #5																		
			GPCEM5B	358,000	3,090,600	1441.837	-1225.919	149	45.4	12.5	3.8	430	494	19.0	5.8	-550	-69.30	EXP	Yes

TABLE FDEP-1A.1b

SUMMARY OF SO_2 SOURCES INCLUDED IN THE AIR MODELING FOR THE PSD CLASS I INCREMENT CONSUMPTION ANALYSES AT THE CHASSAHOWITZKA NWA

FPL GLADES POWER PARK

Facility ID	Facility Name / Emission Unit Description	EU ID	CALPUFF ID Name	UTM Location X (m)	UTM Location Y (m)	LCC Location X (km)	LCC Location Y (km)	Stack Parameters: Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (g/sec)	PSD Source? * (EXP,CON)	Modeled PSD Source?
0570261	Hillsborough Cty RRF																		
	Municipal Waste Combustor & Auxiliary burners-Unit #1	1	HCRRF1	368,200	3,092,700	1451.629	-1222.050	220	67.1	5.1	1.55	290	416	72.5	22.1	32.86	4.140	CON	Yes
	Municipal Waste Combustor & Auxiliary burners-Unit #2	2	HCRRF2	368,200	3,092,700	1451.629	-1222.050	220	67.1	5.1	1.55	290	416	72.5	22.1	32.86	4.140	CON	Yes
	Municipal Waste Combustor & Auxiliary burners-Unit #3	3	HCRRF3	368,200	3,092,700	1451.629	-1222.050	220	67.1	5.1	1.55	290	416	72.5	22.1	32.86	4.140	CON	Yes
			HCRRF	368,200	3,092,700	1451.629	-1222.050	220	67.1	5.1	1.55	290	416	72.5	22.1	98.58	12.421	CON	Yes
1030117	Pinellas Co. Resource Recovery Facility																		
	Municipal Waste Combustor & Auxiliary burners-Unit #1	1	PCRRF1	335,200	3,084,100	1420.255	-1236.366	165	50.3	8.5	2.59	270	405	71.4	21.8	170.00	21.420	CON	Yes
	Municipal Waste Combustor & Auxiliary burners-Unit #2	2	PCRRF2	335,200	3,084,100	1420.255	-1236.366	165	50.3	8.5	2.59	270	405	71.4	21.8	170.00	21.420	CON	Yes
	Municipal Waste Combustor & Auxiliary burners-Unit #3	3	PCRRF3	335,200	3,084,100	1420.255	-1236.366	165	50.3	8.5	2.59	270	405	71.4	21.8	170.00	21.420	CON	Yes
			PCRRF	335,200	3,084,100	1420.255	-1236.366	165	50.3	8.5	2.59	270	405	71.4	21.8	510.00	64.260	CON	Yes
0570008	Mosaic Riverview Facility																		
	DAP Manufacturing Plant	7	MOSRIV7	362,900	3,082,500	1,448.126	-1,233.182	126	38.4	8.0	2.44	104	313	34.5	10.5	40.5	5.108	CON	Yes
	No. 3 MAP Plant	22	MOSRIV22	362,900	3,082,500	1,448.126	-1,233.182	133	40.5	7.0	2.13	142	334	71.5	21.8	0.001	0.000	CON	Yes
	No. 4 MAP Plant	23	MOSRIV23	362,900	3,082,500	1,448.126	-1,233.182	133	40.5	7.0	2.13	142	334	71.5	21.8	0.001	0.000	CON	Yes
	South Cooler	24	MOSRIV24	362,900	3,082,500	1,448.126	-1,233.182	133	40.5	7.0	2.13	142	334	71.5	21.8	0.001	0.000	CON	Yes
	No. 5 DAP Plant	55	MOSRIV55	362,900	3,082,500	1,448.126	-1,233.182	133	40.5	7.0	2.13	110	316	67.6	20.6	12.6	1.585	CON	Yes
			MOSRIV55	362,900	3,082,500	1,448.126	-1,233.182	133	40.5	7.0	2.13	110	316	67.6	20.6	12.6	1.585	CON	Yes
	No. 7 SAP	4	MOSRIV4	362,900	3,082,500	1,448.126	-1,233.182	150	45.7	7.5	2.29	152	340	41.5	12.6	466.7	58.804	NO	No
	No. 8 SAP	5	MOSRIV5	362,900	3,082,500	1,448.126	-1,233.182	150	45.7	8.0	2.44	165	347	42.9	13.1	393.8	49.613	NO	No
	No. 9 SAP	6	MOSRIV6	362,900	3,082,500	1,448.126	-1,233.182	150	45.7	9.0	2.74	155	341	44.8	13.7	495.8	62.475	NO	No
	Animal Feed Ingredient Plant No. 1	78	MOSRIV78	362,900	3,082,500	1,448.126	-1,233.182	136	41.5	6.0	1.83	150	339	64.5	19.7	25.4	3.195	CON	Yes
	Animal Feed Ingredient Plant No. 2	103	MOSRI103	362,900	3,082,500	1,448.126	-1,233.182	155	47.2	6.0	1.83	150	339	64.5	19.7	38.0	4.793	CON	Yes
			MOSRIV78	362,900	3,082,500	1,448.126	-1,233.182	136	41.5	6.0	1.83	150	339	64.5	19.7	63.4	7.988	CON	Yes
	Baseline - Sodium Fluoride Plant		SSFSFPB	362,900	3,082,500	1,448.126	-1,233.182	28	8.5	2.5	0.76	95	308	11.6	3.5	-0.20	-0.025	EXP	Yes
	Baseline - No. 10 KVS Mill		10KVSMB	362,900	3,082,500	1,448.126	-1,233.182	87	26.5	1.7	0.52	118	321	59.8	18.2	-0.02	-0.003	EXP	Yes
	Baseline - No. 12 KVS Mill		12KVSMB	362,900	3,082,500	1,448.126	-1,233.182	71	21.6	1.6	0.49	135	330	68.5	20.9	-0.04	-0.005	EXP	Yes
	Baseline - No. 5 and No. 9 Mills Bag Filter		RKML59B	362,900	3,082,500	1,448.126	-1,233.182	66	20.1	2.0	0.61	115	319	58.3	17.8	-0.01	-0.001	EXP	Yes
			SSFSFPB	362,900	3,082,500	1,448.126	-1,233.182	28	8.5	2.5	0.76	95	308	11.6	3.5	-0.27	-0.034	EXP	Yes
	Baseline - No. 7 Oil-Fired Concentrator		7OFCONB	362,900	3,082,500	1,448.126	-1,233.182	78	23.8	6.0	1.83	165	347	17.2	5.2	-41.4	-5.216	EXP	Yes
	Baseline - No. 8 Oil-Fired Concentrator		8OFCONB	362,900	3,082,500	1,448.126	-1,233.182	78	23.8	6.0	1.83	159	344	16.7	5.1	-39.7	-5.002	EXP	Yes
	Baseline - GTSP Plant		GTSPAPB	362,900	3,082,500	1,448.126	-1,233.182	126	38.4	8.0	2.44	129	327	34.9	10.7	-71.4	-8.996	EXP	Yes
			8OFCONB	362,900	3,082,500	1,448.126	-1,233.182	78	23.8	6.0	1.83	159	344	16.7	5.1	-152.5	-19.215	EXP	Yes
	Baseline - Ammonia Plant		AMMPLTB	362,900	3,082,500	1,448.126	-1,233.182	60	18.3	8.3	2.53	600	589	22.7	6.9	-32.8	-4.133	EXP	Yes
	Baseline - No. 3 Continuous Triple Dryer		3CONTDB	362,900	3,082,500	1,448.126	-1,233.182	68	20.7	3.5	1.07	115	319	45.8	14.0	-22.8	-2.873	EXP	Yes
	Baseline - No. 4 Continuous Triple Dryer		4CONTDB	362,900	3,082,500	1,448.126	-1,233.182	68	20.7	3.5	1.07	134	330	61.8	18.8	-23.2	-2.923	EXP	Yes
			AMMPLTB	362,900	3,082,500	1,448.126	-1,233.182	60	18.3	8.3	2.53	600	589	22.7	6.9	-78.8	-9.929	EXP	Yes
	Baseline - No. 4 Sulfuric Acid Plant		NO4SAPB	362,900	3,082,500	1,448.126	-1,233.182	80	24.4	4.7	1.43	194	363	20.4	6.2	-282.0	-35.532	EXP	Yes
	Baseline - No. 5 Sulfuric Acid Plant		NO5SAPB	362,900	3,082,500	1,448.126	-1,233.182	74	22.6	5.3	1.62	189	360	25.3	7.7	-480.0	-60.480	EXP	Yes
	Baseline - No. 6 Sulfuric Acid Plant		NO6SAPB	362,900	3,082,500	1,448.126	-1,233.182	72	21.9	5.9	1.80	189	360	31.3	9.5	-688.0	-86.658	EXP	Yes
	Baseline - No. 7 Sulfuric Acid Plant		NO7SAPB	362,900	3,082,500	1,448.126	-1,233.182	92	28.0	9.4	2.87	183	357	22.3	6.8	-1503.0	-189.378	EXP	Yes
	Baseline - No. 8 Sulfuric Acid Plant		NO8SAPB	362,900	3,082,500	1,448.126	-1,233.182	96	29.3	10.7	3.26	174	352	24.2	7.4	-1679.0	-211.554	EXP	Yes
			NO7SAPB	362,900	3,082,500	1,448.126	-1,233.182	92	28.0	9.4	2.87	183	357	22.3	6.8	-4632.0	-583.632	EXP	Yes
0694801	Lake Cogen																		
	Combined Cycle CT Units 3 and 4		LAKECOGN	434,000	3,198,800	1498.487	-1104.549	100	30.5	11	3.4	232	384	56.2	17.1	80	10.08	CON	Yes
1050004	C.D. McIntosh, Jr. Power Plant																		
	McIntosh Unit 1	1	MCINT1	409,000	3,106,200	1489.890	-1201.443	150	45.7	9	2.7	277	409	81.2	24.7	2612.5	329.18	NO	No
	Diesel Engine Peaking Unit 2	2	MCINT2	409,000	3,106,200	1489.890	-1201.443	20	6.1	2.6	0.8	715	653	77.0	23.5	14.30	1.80	NO	No
	Diesel Engine Peaking Unit 3	3	MCINT3	409,000	3,106,200	1489.890	-1201.443	20	6.1	2.6	0.8	715	653	77.0	23.5	14.30	1.80	NO	No
	Gas Turbine Peaking Unit 1	4	MCINT4	409,000	3,106,200	1489.890	-1201.443	35	10.7	13.5	4.1	900	755	79.5	24.2	164.70	20.75	NO	No
	McIntosh Unit 2	5	MCINT5	409,000	3,106,200	1489.890	-1201.443	157	47.9	10.5	3.2	277	409	73.2	22.3	892.0	112.39	CON	Yes
	McIntosh Unit 3	6	MCINT6	409,000	3,106,200	1489.890	-1201.443	250	76.2	18	5.5	167	348	82.6	25.2	4368.0	550.37	CON	Yes
	Combustion Turbine Unit 5	28	MCINT28	409,000	3,106,200	1489.890	-1201.443	85	25.9	28	8.5	1095	864	82.7	25.2	8.0	1.01	CON	Yes
	Borden Polk																		
			BORDPLK	414,500	3,109,000	1494.873	-1197.681	56	17.1	7.7	2.3	140	333	27.1	8.3	-41.89	-5.28	EXP	Yes

TABLE FDEP-1A.1b
SUMMARY OF SO_2 SOURCES INCLUDED IN THE AIR MODELING FOR THE PSD CLASS I INCREMENT CONSUMPTION ANALYSES AT THE CHASSAHOWITZKA NWA
FPL GLADES POWER PARK

Facility ID	Facility Name / Emission Unit Description	EU ID	CALPUFF ID Name	UTM Location X (m)	UTM Location Y (m)	LCC Location X (km)	LCC Location Y (km)	Stack Parameters: Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (g/sec)	PSD Source? [a] (EXP/CON)	Modeled PSD Source?
1050003	Lakeland Electric, Larsen Power Plant																		
	Steam Generator # 6	3	LARPWR3	408,900	3,102,500	1490.439	-1205.163	165	50.3	10.0	3.05	340	444	21.0	6.4	841.2	105.99	NO	No
	Steam Generator # 7	4	LARPWR4	408,900	3,102,500	1490.439	-1205.163	165	50.3	10.0	3.05	340	444	22.0	6.7	1643.0	207.02	NO	No
	Peaking Gas Turbine # 3	5	LARPWR5	408,900	3,102,500	1490.439	-1205.163	31	9.4	11.8	3.60	800	700	101.0	30.8	106.20	13.38	NO	No
	Peaking Gas Turbine # 2	6	LARPWR6	408,900	3,102,500	1490.439	-1205.163	31	9.4	11.8	3.60	800	700	101.0	30.8	106.20	13.38	NO	No
	Peaking Gas Turbine # 1	7	LARPWR7	408,900	3,102,500	1490.439	-1205.163	31	9.4	11.8	3.60	800	700	101.0	30.8	-106.20	-13.38	EXP	Yes
	Combined Cycle CT	8	LARPWR8	408,900	3,102,500	1490.439	-1205.163	155	47.2	16.0	4.88	481	523	85.7	26.1	211.4	26.64	CON	Yes
	Big Bend Transfer Co. L.L.C																		
	Melter/Molten Scrubber Stack		BBTCCMBO	361100	3076200	1447.429	-1239.803	95	29.0	2.2	0.7	97	309	57	17.4	0.014	0.002	CON	Yes
	Package Boiler		BBTCPKBL	361100	3076200	1447.429	-1239.803	106	32.3	4	1.2	350	450	29.7	9.1	3.56	0.45	CON	Yes
0570039	TECO - Big Bend Station																		
	Unit #1 Coal Fired Boiler w/ ESP	1	TECOBB1	361,900	3,075,000	1,448.435	-1,240.867	490	149.35	24.0	7.3	294	419	115.9	35.3	26240.5	3306.30	NO	No
	Unit #2 Riley-Stoker Coal Boiler w/ Esp	2	TECOBB2	361,900	3,075,000	1,448.435	-1,240.867	490	149.35	24.0	7.3	125	325	87.6	26.7	25974.0	3272.72	NO	No
	Unit #3 Riley-Stoker Coal Boiler w/ ESP	3	TECOBB3	361,900	3,075,000	1,448.435	-1,240.867	499	152.10	24.0	7.3	279	410	47.0	14.3	26747.5	3370.19	CON	Yes
	Unit #4 Coal Boiler W/ Belco ESP Psd-FI-040	4	TECOBB4	361,900	3,075,000	1,448.435	-1,240.867	499	152.10	24.0	7.3	156	342	59.0	18.0	3551.0	447.43	CON	Yes
			TECOBB3	361,900	3,075,000	1,448.435	-1,240.867	499	152.10	24.0	7.3	279	410	47.0	14.3	30298.5	3817.61	CON	Yes
	Combustion Turbine #2 - No. 2 Fuel Oil	5	TECOBB5	361,900	3,075,000	1,448.435	-1,240.867	75	22.86	14.0	4.3	928	771	61.0	18.6	277.0	34.90	NO	No
	Combustion Turbine #3 - No. 2 Fuel Oil	6	TECOBB6	361,900	3,075,000	1,448.435	-1,240.867	75	22.86	14.0	4.3	928	771	61.0	18.6	277.0	34.90	NO	No
	Combustion Turbine #1 - No. 2 Fuel Oil	7	TECOBB7	361,900	3,075,000	1,448.435	-1,240.867	35	10.67	11.0	3.4	1010	816	91.9	28.0	79.0	9.95	NO	No
	Steam Generators 1 & 2 Baseline	16	TCBB12B	361,900	3,075,000	1,448.435	-1,240.867	490	149.35	24.0	7.3	300	422	94.0	28.7	-19333.3	-2436.0	EXP	Yes
	Steam Generator 3 Baseline	17	TCBB3B	361,900	3,075,000	1,448.435	-1,240.867	490	149.35	24.0	7.3	293	418	47.0	14.3	-9666.7	-1218.0	EXP	Yes
			TCBB3B	361,900	3,075,000	1,448.435	-1,240.867	490	149.35	24.0	7.3	293	418	47.0	14.3	-29000.0	-3654.0	EXP	Yes
0571242	National Gypsum - Apollo Beach																		
	IMP Mill #1		NATGYP1	363,300	3,075,600	1449.726	-1240.023	98	29.9	3.8	1.2	350	450	28.2	8.6	5.28	0.67	CON	Yes
	IMP Mill #2		NATGYP2	363,300	3,075,600	1449.726	-1240.023	98	29.9	3.8	1.2	350	450	28.2	8.6	5.28	0.67	CON	Yes
	IMP Mill #3		NATGYP3	363,300	3,075,600	1449.726	-1240.023	98	29.9	3.8	1.2	350	450	28.2	8.6	5.28	0.67	CON	Yes
	IMP Mill #4		NATGYP4	363,300	3,075,600	1449.726	-1240.023	98	29.9	3.8	1.2	350	450	28.2	8.6	5.28	0.67	CON	Yes
			NATGYP	363,300	3,075,600	1449.726	-1240.023	98	29.9	3.8	1.2	350	450	28.2	8.6	21.12	2.66	CON	Yes
	Kiln		NATGYP5	363,300	3,075,600	1449.726	-1240.023	54	16.5	13.4	4.1	384	469	58.2	17.7	33.22	4.19	CON	Yes
	Ridge Cogeneration																		
			RIDGE	416,700	3,100,400	1498.572	-1205.903	325	99.1	10	3.0	170	350	47.6	14.5	109.52	13.80	CON	Yes
1050023	Cutrale Citrus Juices USA, Inc.																		
	Citrus Feed Mill Dryer	1	CCJUSA1	421,600	3,103,700	1502.870	-1201.744	93	28.3	3.5	1.07	140	333	55.0	16.8	186.0	23.44	NO	No
	Peel Dryer	3	CCJUSA3	421,600	3,103,700	1502.870	-1201.744	100	30.5	3.2	0.98	161	345	49.0	14.9	186.0	23.44	CON	Yes
	Cogeneration System No. 1	8	CCJUSA8	421,600	3,103,700	1502.870	-1201.744	40	12.2	4.0	1.22	323	435	60.0	18.3	170.8	21.52	CON	Yes
	Cogeneration System No. 2	9	CCJUSA9	421,600	3,103,700	1502.870	-1201.744	40	12.2	4.0	1.22	330	439	66.0	20.1	26.0	3.28	CON	Yes
			CCJUSA8	421,600	3,103,700	1502.870	-1201.744	40	12.2	4.0	1.22	323	435	60.0	18.3	196.8	24.80	CON	Yes
0950111	Reedy Creek Energy Services- EPCOT																		
	Generator 1		EPCOT1	442,000	3,139,000	1516.955	-1162.870	17	5.2	1.8	0.5	650	616	144.8	44.1	14.52	1.83	CON	Yes
	Generator 2		EPCOT1	442,000	3,139,000	1516.955	-1162.870	17	5.2	1.8	0.5	650	616	144.8	44.1	14.52	1.83	CON	Yes
			EPCOT	442,000	3,139,000	1516.955	-1162.870	17	5.2	1.8	0.5	650	616	144.8	44.1	29.04	3.66	CON	Yes
0010087	FL Rock Thompson S. Baker Cement Plant																		
			FRBCP	348,400	3,287,000	1398.220	-1031.501	250	76.2	9.42	2.9	356	453	47.8	14.6	17.7	2.23	CON	Yes

TABLE FDEP-1A.1b

SUMMARY OF SO_2 SOURCES INCLUDED IN THE AIR MODELING FOR THE PSD CLASS I INCREMENT CONSUMPTION ANALYSES AT THE CHASSAHOWITZKA NWA

FPL GLADES POWER PARK

Facility ID	Facility Name / Emission Unit Description	EU ID	CALPUFF ID Name	UTM Location X (m)	UTM Location Y (m)	LCC Location X (km)	LCC Location Y (km)	Stack Parameters: Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (g/sec)	PSD Source? [a] (EXP/CON)	Modeled PSD Source?
1050059	Mosaic Fertilizer - New Wales																		
	Sulfuric Acid Plant No. 1	2	WALES2	396,700	3,079,400	1482.337	-1230.415	200	61.0	8.50	2.59	170	350	50.0	15.24	483.30	60.896	NO	No
	Sulfuric Acid Plant No. 2	3	WALES3	396,700	3,079,400	1482.337	-1230.415	200	61.0	8.50	2.59	170	350	50.0	15.24	483.30	60.896	NO	No
	Sulfuric Acid Plant No. 3	4	WALES4	396,700	3,079,400	1482.337	-1230.415	200	61.0	8.50	2.59	170	350	50.0	15.24	483.30	60.896	NO	No
	DAP Plant No. 1	9	WALES9	396,700	3,079,400	1482.337	-1230.415	133	40.5	7.00	2.13	105	314	49.0	14.94	74.60	9.400	NO	No
	AFI Plant	27	WALES27	396,700	3,079,400	1482.337	-1230.415	172	52.4	8.00	2.44	130	328	66.3	20.21	18.30	2.306	CON	Yes
	Multifos A and B Kilns, Dryer and Blending Operation	36	WALES36	396,700	3,079,400	1482.337	-1230.415	172	52.4	4.50	1.37	105	314	52.0	15.85	192.00	24.192	CON	Yes
	Sulfuric Acid Plant No. 4	42	WALES42	396,700	3,079,400	1482.337	-1230.415	199	60.7	8.50	2.59	170	350	50.0	15.24	483.30	60.896	CON	Yes
	Sulfuric Acid Plant No. 5	44	WALES44	396,700	3,079,400	1482.337	-1230.415	199	60.7	8.50	2.59	170	350	50.0	15.24	483.30	60.896	CON	Yes
	DAP Plant No 2 - East Train	45	WALES45	396,700	3,079,400	1482.337	-1230.415	171	52.1	6.00	1.83	110	316	58.0	17.68	22.00	2.772	CON	Yes
	DAP Plant No 2 - West Train	46	WALES46	396,700	3,079,400	1482.337	-1230.415	171	52.1	6.00	1.83	110	316	58.0	17.68	22.00	2.772	CON	Yes
			WALES36	396,700	3,079,400	1482.337	-1230.415	172	52.4	4.50	1.37	105	314	52.0	15.85	1220.90	153.833	CON	Yes
	7500 Ton Rail Molten Storage Tank	60	WALES60	396,700	3,079,400	1482.337	-1230.415	40	12.2	2.00	0.61	240	389	0.42	0.13	0.50	0.063	CON	Yes
	5000 Ton Molten Storage Tank	62	WALES62	396,700	3,079,400	1482.337	-1230.415	40	12.2	2.00	0.61	240	389	0.42	0.13	0.50	0.063	CON	Yes
	350 Ton Truck Unloading Sulfur Pit, Vent	69	WALES69	396,700	3,079,400	1482.337	-1230.415	25	7.6	0.10	0.03	90	305	0.1	0.03	0.10	0.013	CON	Yes
			WALES69	396,700	3,079,400	1482.337	-1230.415	25	7.6	0.10	0.03	90	305	0.1	0.03	1.10	0.139	CON	Yes
	1500 Ton Truck Unloading Sulfur Pit	63	WALES63	396,700	3,079,400	1482.337	-1230.415	40	12.2	2.00	0.61	240	389	0.42	0.13	0.30	0.038	NO	No
	350 Ton Truck Unloading Sulfur Pit	64	WALES64	396,700	3,079,400	1482.337	-1230.415	40	12.2	2.00	0.61	240	389	0.42	0.13	0.10	0.013	NO	No
	Railcar Unloading Pit	65	WALES65	396,700	3,079,400	1482.337	-1230.415	40	12.2	2.00	0.61	240	389	0.42	0.13	0.30	0.038	NO	No
	200 Ton Molten Sulfur Transfer Pit	66	WALES66	396,700	3,079,400	1482.337	-1230.415	40	12.2	2.00	0.61	240	389	0.42	0.13	0.10	0.013	NO	No
	1500 Ton Truck Unloading Sulfur Pit, Front Vent	67	WALES67	396,700	3,079,400	1482.337	-1230.415	25	7.6	0.10	0.03	90	305	0.1	0.03	0.30	0.038	NO	No
	1500 Ton Truck Unloading Sulfur Pit, Rear Vent	68	WALES68	396,700	3,079,400	1482.337	-1230.415	25	7.6	0.10	0.03	90	305	0.1	0.03	0.30	0.038	NO	No
	Multifos C Kiln	74	WALES74	396,700	3,079,400	1482.337	-1230.415	172	52.4	4.50	1.37	105	314	70.2	21.40	8.70	1.096	NO	No
	GRANULAR MAP PLANT	78	WALES78	396,700	3,079,400	1482.337	-1230.415	133	40.5	6.00	1.83	145	336	109.6	33.41	13.72	1.729	NO	No
	89.5 MMBTU/hr. boiler (non-NSPS) - rental boiler	81	WALES81	396,700	3,079,400	1482.337	-1230.415	18	5.5	3.60	1.10	400	478	34.9	10.64	4.30	0.542	NO	No
	Expanding Source		IMCWAL0	396,700	3,079,400	1482.337	-1230.415	69	21.0	7.0	2.13	165	347	61.0	18.59	-272.0	-34.3	EXP	Yes
	Expanding Source		IMCWAL1	396,700	3,079,400	1482.337	-1230.415	200	61.0	8.5	2.59	170	350	42.9	13.08	-1,158.7	-146.0	EXP	Yes
1050046	Mosaic Fertilizer - Bartow																		
	NO 3 FERTILIZER PLANT	1	MFBAR1	409,800	3,086,600	1494.124	-1220.921	99	30.18	7.5	2.29	135	330	53	16.15	76.90	9.69	CON	Yes
	NO 4 FERTILIZER PLANT	21	MFBAR21	409,800	3,086,600	1494.124	-1220.921	140	42.67	10.9	3.32	132	329	53	16.15	102.53	12.92	CON	Yes
	Cleaver Brooks Package Watertube Boiler	51	MFBAR51	409,800	3,086,600	1494.124	-1220.921	31	9.45	3.5	1.07	410	483	20	6.10	165.17	20.81	CON	Yes
	No. 4 Sulfuric Acid Plant	12	MFBAR12	409,800	3,086,600	1494.124	-1220.921	200	60.96	6.8	2.07	180	355	61	18.59	433.30	54.60	CON	Yes
	No. 6 Sulfuric Acid Plant	32	MFBAR32	409,800	3,086,600	1494.124	-1220.921	200	60.96	6.8	2.07	180	355	61	18.59	433.30	54.60	CON	Yes
	No. 5 Sulfuric Acid Plant	33	MFBAR33	409,800	3,086,600	1494.124	-1220.921	200	60.96	6.8	2.07	180	355	61	18.59	433.30	54.60	CON	Yes
			MFBARSAP	409,800	3,086,600	1494.124	-1220.921	200	60.96	6.8	2.07	180	355	61	18.59	1,299.90	163.79	CON	Yes
	Mulberry - No. 3 Sulfuric Acid Plant	2	MFMUL2	406,800	3,085,100	1491.399	-1222.947	200	61.0	7.0	2.13	200	366	32.0	9.8	283.33	35.70	NO	No
	Mulberry - MAP/DAP Plant Scrubber	5	MFMUL5	406,800	3,085,100	1491.399	-1222.947	102	31.1	8.8	2.68	110	316	26.0	7.9	-73.79	-9.30	EXP	Yes
	Mulberry - Nebraska Model NS-E-65 Steam Boiler	9	MFMUL9	406,800	3,085,100	1491.399	-1222.947	45	13.7	3.7	1.13	80	300	8.0	2.4	102.44	12.91	NO	No
	Mulberry - Expanding Source		MFMULX	406,800	3,085,100	1491.399	-1222.947	168	51.2	7.0	2.13	181	356	37.5	11.4	-2,044.40	-257.59	EXP	Yes
1050057	Mosaic Fertilizer - Nichols																		
	Phosphate Rock Dryer W/ Wet Scrubber - Expanding Source	12	MFNIC12	398,400	3,084,200	1,483.190	-1,225.312	81	24.7	7.5	2.3	130	328	12.0	3.7	-26.49	-3.34	EXP	Yes
	Package Boiler (North Standby Boiler) - Expanding Source	15	MFNIC15	398,400	3,084,200	1,483.190	-1,225.312	27	8.2	2.0	0.6	500	533	45.0	13.7	-12.80	-1.61	EXP	Yes
	Package Boiler - Expanding Source	16	MFNIC16	398,400	3,084,200	1,483.190	-1,225.312	39	11.9	3.2	1.0	500	533	29.0	8.8	-25.60	-3.23	EXP	Yes
	Expanding Source		MFNK1B	398,400	3,084,200	1,483.190	-1,225.312	100	30.5	5.9	1.8	95	308	62.0	18.9	-121.0	-15.25	EXP	Yes
	Expanding Source		MFNK2B	398,400	3,084,200	1,483.190	-1,225.312	80	24.4	5.0	1.5	151	339	42.3	12.89	-30.20	-3.81	EXP	Yes
1050047	Agrifos Mining, L.L.C. - Nichols																		
	Rock Dryer N. 1	1	AGRNIC1	398,700	3,085,300	1,483.296	-1,224.159	80	24.4	7.5	2.29	160	344	41.0	12.5	255.5	32.20	CON	Yes
	Rock Dryer N. 2	2	AGRNIC2	398,700	3,085,300	1,483.296	-1,224.159	80	24.4	7.5	2.29	160	344	41.0	12.5	251.0	31.63	CON	Yes
			AGRINIC	398,700	3,085,300	1,483.296	-1,224.159	80	24.4	7.5	2.29	160	344	41.0	12.5	506.5	63.82	CON	Yes
	Expanding Source		AGRINK3	398,700	3,085,300	1,483.296	-1,224.159	93	28.3	3.6	1.10	152	340	63.1	19.2	-110.32	-13.90	EXP	Yes
	Expanding Source		AGRINK4	398,700	3,085,300	1,483.296	-1,224.159	13	4.0	2.6	0.79	480	522	5.9	1.8	-6.90	-0.87	EXP	Yes

TABLE FDEP-1A.1b

SUMMARY OF SO_2 SOURCES INCLUDED IN THE AIR MODELING FOR THE PSD CLASS I INCREMENT CONSUMPTION ANALYSES AT THE CHASSAHOWITZKA NWA

FPL GLADES POWER PARK

Facility ID	Facility Name / Emission Unit Description	EU ID	CALPUFF ID Name	UTM Location X (m)	UTM Location Y (m)	LCC Location X (km)	LCC Location Y (km)	Stack Height (ft)	Stack Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (g/sec)	PSD Source? * (EXP/CON)	Modeled PSD Source?
1050050	U.S. Agri-Chemical Co. - Bartow																		
			UAGBAR1	413,200	3,086,300	1497.562	-1220.628	52	15.8	6	1.8	138	332	32.8	10.0	-27.06	-3.41	EXP	Yes
			UAGBAR2	413,200	3,086,300	1497.562	-1220.628	95	29.0	7	2.1	89	305	24.6	7.5	-333.33	-42.00	EXP	Yes
	IMC - Agrico Pierce																		
			IAPRC12	401,400	3,079,000	1487.089	-1229.997	80	24.4	5	1.52	151	339	42.5	12.9	-193.02	-24.32	EXP	Yes
			IAPRC34	401,400	3,079,000	1487.089	-1229.997	80	24.4	8	2.43	151	339	61.7	18.8	-182.54	-23.00	EXP	Yes
			IMCAG	401,400	3,079,000	1487.089	-1229.997	80	24.4	5	1.52	151	339	42.5	12.9	-375.56	-47.32	EXP	Yes
	Mobil Electrophos Division																		
			MOBELE1	405,600	3,079,400	1491.203	-1228.864	24	7.3	3	0.9	376	464	10.6	3.2	-51.83	-6.53	EXP	Yes
			MOBELE2	405,600	3,079,400	1491.203	-1228.864	20	6.1	3	0.9	376	464	25.3	7.7	-79.76	-10.05	EXP	Yes
			MOBELE3	405,600	3,079,400	1491.203	-1228.864	60	18.3	6	1.8	170	350	22.3	6.8	-173.1	-21.81	EXP	Yes
			MOBELE4	405,600	3,079,400	1491.203	-1228.864	84	25.6	7	2.1	91	306	22.9	7.0	-56.43	-7.11	EXP	Yes
			MOBELE5	405,600	3,079,400	1491.203	-1228.864	60	18.3	2.3	0.7	120	322	75.0	22.9	-25.16	-3.17	EXP	Yes
			MOBELE6	405,600	3,079,400	1491.203	-1228.864	96	29.3	7	2.1	106	314	28.0	8.5	-375	-47.25	EXP	Yes
1050053	Mosaic Fertilizer - Green Bay																		
	No. 4 Sulfuric Acid Plant	4	MOSGB4	409,500	3,080,100	1,494.965	-1,227.482	100	30.5	7.5	2.29	180	355	39.6	12.1	350.0	44.10	NO	No
	South DAP Plant--Stack B (Dryer)	7	MOSGB7B	409,500	3,080,100	1,494.965	-1,227.482	129.5	39.5	7.5	2.29	107.6	315	52.6	16.0	55.2	6.95	NO	No
	North AP Plant-Main Stack	29	MOSGB29M	409,500	3,080,100	1,494.965	-1,227.482	129.5	39.5	7.5	2.29	104.5	313	68.2	20.8	32.4	4.09	NO	No
	No. 5 Sulfuric Acid Plant	5	MOSGB5	409,500	3,080,100	1,494.965	-1,227.482	150	45.7	8.0	2.44	180	355	44.1	13.4	466.7	58.80	CON	Yes
	No. 6 Sulfuric Acid Plant	38	MOSGB38	409,500	3,080,100	1,494.965	-1,227.482	150	45.7	9.0	2.74	180	355	34.8	10.6	401.0	50.53	CON	Yes
			MOSGB38	409,500	3,080,100	1,494.965	-1,227.482	150	45.7	9.0	2.74	180	355	34.8	10.6	867.7	109.33	CON	Yes
	Molten Sulfur Storage Tank 1 - 6000 Short Tons, 9 Vents	30	MFGB30	409,500	3,080,100	1,494.965	-1,227.482	40	12.2	2.0	0.61	120	322	0.1	0.03	1.20	0.15	CON	Yes
	Molten Sulfur Storage Tank 2 (East)-2500 Short Tons, 10 Vent	31	MFGB31	409,500	3,080,100	1,494.965	-1,227.482	40	12.2	2.0	0.61	120	322	0.1	0.03	1.2	0.15	CON	Yes
	Molten Sulfur Storage Tank 3 (West)-2500 Short Tons, 10 Vent	32	MFGB32	409,500	3,080,100	1,494.965	-1,227.482	40	12.2	2.0	0.61	120	322	0.1	0.03	1.2	0.15	CON	Yes
	Molten Sulfur Truck Pit - 72 Short Tons, 1 Vent	33	MFGB33	409,500	3,080,100	1,494.965	-1,227.482	40	12.2	2.0	0.61	120	322	0.1	0.03	0.1	0.01	CON	Yes
	Molten Sulfur Rail (And Back-Up Truck) Pit - 91 Short Tons	34	MFGB34	409,500	3,080,100	1,494.965	-1,227.482	40	12.2	2.0	0.61	120	322	0.1	0.03	0.7	0.09	CON	Yes
	Molten Sulfur No. 5 Supply Pit - 31 Short Tons.	35	MFGB35	409,500	3,080,100	1,494.965	-1,227.482	40	12.2	2.0	0.61	200	366	0.1	0.03	0.1	0.01	CON	Yes
	Molten Sulfur Supply Pit #3 & #4 - 28 Short Tons, One Vent	36	MFGB36	409,500	3,080,100	1,494.965	-1,227.482	10	3.0	0.5	0.15	200	366	0.1	0.03	0.1	0.01	CON	Yes
			MFGB30	409,500	3,080,100	1,494.965	-1,227.482	40	12.2	2.0	0.61	120	322	0.1	0.03	4.60	0.58	CON	Yes
	SAP # 1 (Expanding Source)		GBSAP1B	409,500	3,080,100	1,494.965	-1,227.482	100	30.5	7.0	2.13	169	349	18.9	5.5	-493	-62.10	EXP	Yes
	SAP # 2 (Expanding Source)		GBSAP2B	409,500	3,080,100	1,494.965	-1,227.482	100	30.5	7.0	2.13	171	350	18.8	5.7	-533	-67.13	EXP	Yes
	SAP # 3 (Expanding Source)		GBSAP3B	409,500	3,080,100	1,494.965	-1,227.482	100	30.5	7.5	2.29	162	345	30.3	9.2	-653	-82.23	EXP	Yes
	SAP # 4 (Expanding Source)		GBSAP4B	409,500	3,080,100	1,494.965	-1,227.482	100	30.5	7.5	2.29	124	324	22.7	6.9	-542	-68.34	EXP	Yes
			GBSAPB	409,500	3,080,100	1,494.965	-1,227.482	100	30.5	7.0	2.13	169	349	18.9	5.8	-2,221	-279.80	EXP	Yes
0970014	Progress Energy - Intercession City Plant																		
	CT Peaking Units 1-6	1-6	ICP16	446,300	3,126,000	1523.522	-1175.112	45	13.72	14.6	4.46	760	678	174.9	53.3	2185.2	275.34	NO	No
	CTs 7-10	7-10	ICP710	446,300	3,126,000	1523.522	-1175.112	50	15.24	13.8	4.19	1043	835	174.1	53.1	888.0	111.89	CON	Yes
	CT # 11	11	ICP11	446,300	3,126,000	1523.522	-1175.112	75	22.86	19.0	5.79	1034	830	139.4	42.5	407.0	51.28	CON	Yes
	Simple Cycle CTs P-12, P13 & P-14	18-20	ICP1820	446,300	3,126,000	1523.522	-1175.112	56	17.07	16.1	4.91	993	807	117.6	35.8	147.4	18.57	CON	Yes
0970043	Kissimmee Utilities - Cane Island																		
	Simple Cycle CT Unit 1	1	KUACI1	447,700	3,127,900	1524.579	-1172.967	65	19.8	10	3.0	718	654	95.0	29.0	20	2.52	CON	Yes
	Combined Cycle CT Unit 2	2	KUACI2	447,700	3,127,900	1524.579	-1172.967	75	22.9	10	3.0	718	654	95.0	29.0	52	6.55	CON	Yes
	Combined Cycle CT Unit 3	3	KUACI3	447,700	3,127,900	1524.579	-1172.967	130	39.6	18	5.5	173	351	41.6	12.7	94.6	11.92	CON	Yes
	Borden Hillsborough																		
			BORDHIL	394,600	3,069,600	1481.960	-1240.597	100	30.5	6	1.8	160	344	48.5	14.8	-51.43	-6.48	EXP	Yes
0010006	GRU - Deerhaven Generating Station																		
	Fossil Fuel Fired Steam Generator #1(Phase II AR Unit)	3	GRUDGS3	365,700	3,292,600	1414.383	-1022.938	300	91.4	11	3.4	261	400	47	14.3	2640	332.64	NO	No
	Fossil Fuel Fired Steam Generator #2 (Phase I & II AR Unit)	5	GRUDGS5	365,700	3,292,600	1414.383	-1022.938	350	106.7	18.5	5.6	275	408	50	15.2	2913.6	367.11	CON	Yes
	Simple Cycle Comb Turbine No. 3 (Phase II Acid Rain Unit)	6	GRUDGS6	365,700	3,292,600	1414.383	-1022.938	52	15.8	14.1	4.3	1100	866	168	51.2	53	6.68	CON	Yes
1050217	Mulberry Cogeneration																		
	Combustion Turbine with HRSG	1	MCF1	413,600	3,080,600	1498.961	-1226.266	125	38.1	15	4.6	220	378	64.1	19.5	95.1	11.98	CON	Yes
	Secondary Boiler	2	MCF2	413,600	3,080,600	1498.961	-1226.266	125	38.1	3	0.9	220	378	66.5	20.3	4.67	0.59	CON	Yes
			MCF	413,600	3,080,600	1498.961	-1226.266	125	38.1	15	4.6	220	378	64.1	19.5	99.77	12.57	CON	Yes

TABLE FDEP-1A.1b
SUMMARY OF SO_2 SOURCES INCLUDED IN THE AIR MODELING FOR THE PSD CLASS I INCREMENT CONSUMPTION ANALYSES AT THE CHASSAHOWITZKA NWA
FPL GLADES POWER PARK

Facility ID	Facility Name / Emission Unit Description	EU ID	CALPUFF ID Name	UTM Location X (m)	UTM Location Y (m)	LCC Location X (km)	LCC Location Y (km)	Stack Parameters: Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (g/sec)	PSD Source? [a] (EXP/CON)	Modeled PSD Source?
1050055	Mosaic Phosphates Company - So. Pierce																		
	Auxiliary Boiler	1	MFPIER1	407,500	3,071,400	1,494.498	-1,236.545	35	10.67	4.8	1.46	430	494	51	15.54	63.5	8.00	NO	No
	Sulfuric Acid Plant No. 10	4	MFPIER4	407,500	3,071,400	1,494.498	-1,236.545	144	43.89	9	2.74	170	350	41.1	12.53	450.0	56.70	NO	No
	Sulfuric Acid Plant No. 11	5	MFPIER5	407,500	3,071,400	1,494.498	-1,236.545	144	43.89	9	2.74	170	350	41.1	12.53	450.0	56.70	NO	No
	GTSP Production Plant	23	MFPIER23	407,500	3,071,400	1,494.498	-1,236.545	140	42.67	9	2.74	110	316	36	10.97	170.0	21.42	NO	No
	Molten Sulfur Storage Tank, Truck Pit, and Rail Pit Vents	30-45	MFPIERV	407,500	3,071,400	1,494.498	-1,236.545	24	7.32	1	0.30	200	366	0.33	0.10	6.6	0.83	NO	No
	Combined Expanding Sources		MFPIERB	407,500	3,071,400	1,494.498	-1,236.545	144	43.89	5.2	1.58	170	350	86.6	26.40	-600.0	-75.60	EXP	Yes
	Estech/Swift Polk																		
			ESTDRY1	411,500	3,074,200	1497.992	-1233.042	60	18.3	9.7	3.0	151	339	27.8	8.5	-190.0	-23.94	EXP	Yes
			ESTDRY2	411,500	3,074,200	1497.992	-1233.042	61.5	18.7	9.7	3.0	152	340	16.6	5.1	-181.0	-22.80	EXP	Yes
			ESTSAP	411,500	3,074,200	1497.992	-1233.042	101	30.8	7	2.1	185	358	12.8	3.9	-737.1	-92.87	EXP	Yes
	Imperial Phosphates (Brewer)																		
			IMPRLX	404,800	3,069,500	1492.141	-1238.919	90	27.4	7.5	2.3	151	339	50.0	15.2	-152.86	-19.26	EXP	Yes
	Dolime																		
	Dryers		DOLIMEDR	404,800	3,069,500	1492.141	-1238.919	90.0	27.4	5.0	1.52	140	333	67.8	20.7	-45.08	-5.68	EXP	Yes
	Boilers		DOLIMEBL	404,800	3,069,500	1492.141	-1238.919	90.0	27.4	2.0	0.61	430	494	23.8	7.3	-35.87	-4.52	EXP	Yes
1050233	TECO, Polk Power Station																		
	Combined cycle CT	1	TECOPK1	402,500	3,067,400	1490.217	-1241.424	150	45.7	19	5.6	340	444	75.8	23.1	518	65.27	CON	Yes
	120 MMBtu/HR AuxBlr	3	TECOPK3	402,500	3,067,400	1490.217	-1241.424	75	22.9	3.7	1.1	375	464	50.0	15.2	96	12.10	CON	Yes
	Sulfuric Acid Plant	4	TECOPK4	402,500	3,067,400	1490.217	-1241.424	199	60.7	2.5	0.8	180	355	60.0	18.3	35.6	4.49	CON	Yes
	Simple Cycle CT	9	TECOPK9	402,500	3,067,400	1490.217	-1241.424	114	34.7	29	8.8	1117	876	60.2	18.3	9.2	1.16	CON	Yes
	Simple Cycle CT	10	TECOPK10	402,500	3,067,400	1490.217	-1241.424	114	34.7	29	8.8	1117	876	60.2	18.3	9.2	1.16	CON	Yes
			TECO9&10	402,500	3,067,400	1490.217	-1241.424	114	34.7	29	8.8	1117	876	60.2	18.3	18.4	2.32	CON	Yes
1050234	PE Hines Energy Complex																		
	POWER BLOCK 1, CT 1A	1	HINES1	414,300	3,073,900	1500.835	-1232.853	300	91.4	9.0	2.74	312	429	119.2	36.3	94.0	11.84	CON	Yes
	POWER BLOCK 1, CT 1B	2	HINES2	414,300	3,073,900	1500.835	-1232.853	300	91.4	9.0	2.74	305	425	102.8	31.3	94.0	11.84	CON	Yes
			HINESBL1	414,300	3,073,900	1500.835	-1232.853	300	91.4	9.0	2.74	305	425	102.8	31.3	188.0	23.69	CON	Yes
	POWER BLOCK 2, CT 2A	14	HINES14	414,300	3,073,900	1500.835	-1232.853	125	38.1	19.0	5.79	190	361	59.3	18.1	105.6	13.31	CON	Yes
	POWER BLOCK 2, CT 2B	15	HINES15	414,300	3,073,900	1500.835	-1232.853	125	38.1	19.0	5.79	190	361	59.3	18.1	105.6	13.31	CON	Yes
	POWER BLOCK 3, CT 3A	16	HINES16	414,300	3,073,900	1500.835	-1232.853	125	38.1	19.0	5.79	190	361	59.3	18.1	105.6	13.31	CON	Yes
	POWER BLOCK 3, CT 3B	17	HINES17	414,300	3,073,900	1500.835	-1232.853	125	38.1	19.0	5.79	190	361	59.3	18.1	105.6	13.31	CON	Yes
	POWER BLOCK 4, CT 4A		HINES4A	414,300	3,073,900	1500.835	-1232.853	125	38.1	19.0	5.79	190	361	59.3	18.1	105.6	13.31	CON	Yes
	POWER BLOCK 4, CT 4B		HINES4B	414,300	3,073,900	1500.835	-1232.853	125	38.1	19.0	5.79	190	361	59.3	18.1	105.6	13.31	CON	Yes
			HINES234	414,300	3,073,900	1500.835	-1232.853	125	38.1	19.0	5.79	190	361	59.3	18.1	633.6	79.83	CON	Yes
0970001	Kissimmee Utility Authority--Hansel Plant																		
	Combined Cycle CT	1	KUAHAN1	460,100	3,129,300	1,536.664	-1,169.389	60.0	18.3	12.0	3.7	300	422	65.0	19.8	255.00	32.13	CON	Yes
	Diesel Generator Unit 8	8	KUAHAN8	460,100	3,129,300	1,536.664	-1,169.389	53.0	16.2	2.8	0.9	400	478	9.0	2.7	55.50	6.99	NO	No
	Diesel Generator Unit 14-18	14-18	KUAHAN14	460,100	3,129,300	1,536.664	-1,169.389	44.0	13.4	2.6	0.8	450	505	5.0	1.5	55.50	6.99	NO	No
	Diesel Generator Units 19-20	19-20	KUAHAN19	460,100	3,129,300	1,536.664	-1,169.389	28.0	8.5	3.0	0.9	450	505	7.0	2.1	29.30	3.69	CON	Yes
1270028	Progress Energy Florida - Debary Facility																		
	Peaking Combustion Turbine #1	3	PEDEB3	467,500	3,197,200	1532.022	-1100.273	45	13.7	17.7	5.4	1050	839	173.7	52.9	490	61.74	CON	Yes
	Peaking Combustion Turbine #2	5	PEDEB5	467,500	3,197,200	1532.022	-1100.273	45	13.7	17.7	5.4	1050	839	173.7	52.9	490	61.74	CON	Yes
	Peaking Combustion Turbine #3	7	PEDEB7	467,500	3,197,200	1532.022	-1100.273	45	13.7	17.7	5.4	1050	839	173.7	52.9	490	61.74	CON	Yes
	Peaking Combustion Turbine #4	9	PEDEB9	467,500	3,197,200	1532.022	-1100.273	45	13.7	17.7	5.4	1050	839	173.7	52.9	490	61.74	CON	Yes
	Peaking Combustion Turbine #5	11	PEDEB11	467,500	3,197,200	1532.022	-1100.273	45	13.7	17.7	5.4	1050	839	173.7	52.9	490	61.74	CON	Yes
	Peaking Combustion Turbine #6	13	PEDEB13	467,500	3,197,200	1532.022	-1100.273	45	13.7	17.7	5.4	1050	839	173.7	52.9	490	61.74	CON	Yes
			PEDEBGR1	467,500	3,197,200	1532.022	-1100.273	45	13.7	17.7	5.4	1050	839	173.7	52.9	2940	370.44	CON	Yes
	Combustion Turbine Unit No. 7	15	PEDEB15	467,500	3,197,200	1532.022	-1100.273	50	15.2	13.8	4.2	1043	835	174.1	53.1	555	69.93	CON	Yes
	Combustion Turbine Unit No. 8	16	PEDEB16	467,500	3,197,200	1532.022	-1100.273	50	15.2	13.8	4.2	1043	835	174.1	53.1	555	69.93	CON	Yes
	Combustion Turbine Unit No. 9	17	PEDEB17	467,500	3,197,200	1532.022	-1100.273	50	15.2	13.8	4.2	1043	835	174.1	53.1	555	69.93	CON	Yes
	Combustion Turbine Unit No. 10	18	PEDEB18	467,500	3,197,200	1532.022	-1100.273	50	15.2	13.8	4.2	1043	835	174.1	53.1	555	69.93	CON	Yes
			PEDEBGR2	467,500	3,197,200	1532.022	-1100.273	50	15.2	13.8	4.2	1043	835	174.1	53.1	2220	279.72	CON	Yes

TABLE FDEP-1A.1b

SUMMARY OF SO_2 SOURCES INCLUDED IN THE AIR MODELING FOR THE PSD CLASS I INCREMENT CONSUMPTION ANALYSES AT THE CHASSAHOWITZKA NWA

FPL GLADES POWER PARK

Facility ID	Facility Name / Emission Unit Description	EU ID	CALPUFF ID Name	UTM Location X (m)	UTM Location Y (m)	LCC Location X (km)	LCC Location Y (km)	Stack Parameters Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (g/sec)	PSD Source?* (EXP/CON)	Modeled PSD Source?
1050051	U.S. Agri-Chemicals - Ft. Meade																		
	SAP #1	16	USAGFM16	416,000	3,069,000	1503.389	-1237.464	175	53.3	8.5	2.6	180	355	32.0	9.8	500	63.00	CON	Yes
	SAP #2	17	USAGFM17	416,000	3,069,000	1503.389	-1237.464	175	53.3	8.5	2.6	180	355	32.0	9.8	500	63.00	CON	Yes
			USAGFMG1	416,000	3,069,000	1503.389	-1237.464	175	53.3	8.5	2.6	180	355	32.0	9.8	1000	126.00	CON	Yes
	MOLTEN SULFUR TANK	28	USAGFM28	416,000	3,069,000	1503.389	-1237.464	6	1.8	0.3	0.1	270	405	344.0	104.9	0.49	0.06	CON	Yes
	MOLTEN SULFUR TANK	29	USAGFM29	416,000	3,069,000	1503.389	-1237.464	6	1.8	0.3	0.1	260	400	157.0	47.9	0.23	0.03	CON	Yes
			USAGFMG2	416,000	3,069,000	1503.389	-1237.464	6	1.8	0.3	0.1	270	405	344.0	104.9	0.72	0.09	CON	Yes
	Expanding Source		USAGFM0	416,000	3,069,000	1503.389	-1237.464	95	29.0	9.9	3.0	106	314	23.0	7.0	-625.4	-78.80	EXP	Yes
	Expanding Source		USAGFM1	416,000	3,069,000	1503.389	-1237.464	93	28.3	5	1.5	134	330	58.0	17.7	-145	-18.27	EXP	Yes
			USAGFMG3	416,000	3,069,000	1503.389	-1237.464	95	29.0	9.9	3.0	106	314	23.0	7.0	-770.4	-97.07	EXP	Yes
0490015	Hardee Power Partners, Ltd																		
	Combustion Turbine 1A with HRSG	1	HARDE1	404,800	3,057,400	1494.263	-1251.043	90	27.4	14.5	4.4	236	386	77.5	23.6	734.4	92.53	CON	Yes
	Combustion Turbine 1B with HRSG	2	HARDE2	404,800	3,057,400	1494.263	-1251.043	90	27.4	14.5	4.4	245	391	75.8	23.1	734.4	92.53	CON	Yes
	Simple cycle Combustion Turbine 2A	3	HARDE3	404,800	3,057,400	1494.263	-1251.043	75	22.9	17.9	5.5	986	803	94.3	28.7	734.4	92.53	CON	Yes
	Unit 2B - 75 MW gas turbine	5	HARDE5	404,800	3,057,400	1494.263	-1251.043	80	24.4	14.8	4.5	999	810	142.0	43.3	5.3	0.67	CON	Yes
			HARDEE	404,800	3,057,400	1494.263	-1251.043	90	27.4	14.5	4.4	236	386	77.5	23.6	2208.5	278.27	CON	Yes
	Suwannee American Cement																		
			SUAMC	321400	3315900	1,366.488	-1,007.387	315	96.0	9.42	2.9	205	369	46.4	14.1	28.4	3.58	CON	Yes
	Florida Power & Light - Palatka																		
			FPLPAL	442,800	3,277,600	1493.369	-1024.466	149.9	45.7	13	4.0	275	408	31.2	9.5	-2039.9	-257.03	EXP	Yes
1070014	Florida Power & Light - Putnam																		
	CT/HRSG Units 3,4,5,&6 and Duct Burner Units 7,8,9, & 10		CPFLPUTM	443,300	3,277,600	1493.864	-1024.378	73	22.3	48	14.6	328	438	96.1	29.3	3300	415.80	CON	Yes
1070005	Georgia-Pacific Corp. Pulp/Paper Mill																		
	No. 4 Smelt Dissolving Tanks	19	SDT4	434,000	3,283,400	1483.634	-1020.228	206.0	62.8	5	1.5	179.3	355	33.9	10.3	7.7	0.97	CON	Yes
	No. 5 Power Boiler	15	PB524	434,000	3,283,400	1483.634	-1020.228	236.8	72.2	8	2.4	413.3	485	85.9	26.2	1461.9	184.20	CON	Yes
	No. 4 Combination Boiler	16	CB4	434,000	3,283,400	1483.634	-1020.228	236.8	72.2	8	2.4	465.5	514	92.3	28.1	961.1	121.10	CON	Yes
	No. 4 Recovery Boiler	18	RB4_24HR	434,000	3,283,400	1483.634	-1020.228	229.9	70.1	12	3.7	424.1	491	65.9	20.1	109.8	13.84	CON	Yes
	No. 7 Package Boiler Replacing Unit 034	44	PB7	434,000	3,283,400	1483.634	-1020.228	60.0	18.3	7	2.1	749.9	672	43.5	13.2	0.2	0.02	CON	Yes
	No. 4 Lime Kiln	17	LK4	434,000	3,283,400	1483.634	-1020.228	130.9	39.9	4	1.3	164.0	347	70.6	21.5	34.5	4.35	CON	Yes
			TM5P	434,000	3,283,400	1483.634	-1020.228	94.0	28.6	4	1.3	450.1	505	77,080	23.5	0.0	0.00	CON	Yes
	Thermal Oxidizer	37	TOX	434,000	3,283,400	1483.634	-1020.228	249.9	76.2	4	1.1	159.5	344	18.0	5.5	31.3	3.94	CON	Yes
	No. 1 Recovery Boiler		RB1B	434,000	3,283,400	1483.634	-1020.228	249.9	76.2	12	3.7	188.3	360	28.9	8.8	-49.3	-6.21	EXP	Yes
	No. 2 Recovery Boiler		RB2B	434,000	3,283,400	1483.634	-1020.228	249.9	76.2	12	3.7	209.9	372	28.9	8.8	-70.5	-8.88	EXP	Yes
	No. 4 Recovery Boiler		RB4B	434,000	3,283,400	1483.634	-1020.228	229.9	70.1	12	3.7	393.5	474	55.3	16.9	-277.8	-35.00	EXP	Yes
	No. 5 Power Boiler	15	PB5B	434,000	3,283,400	1483.634	-1020.228	239.1	72.9	9	2.7	476.3	520	52.4	16.0	-1277.8	-161.00	EXP	Yes
	No. 4 Combination Boiler		CB4B	434,000	3,283,400	1483.634	-1020.228	239.1	72.9	10	3.0	398.9	477	34.5	10.5	-960.3	-121.00	EXP	Yes
			RB1234B	434,000	3,283,400	1483.634	-1020.228	239.1	72.9	10	3.0	398.9	477	34.5	10.5	-2635.6	-332.09	EXP	Yes
	No. 3 Recovery Boiler		RB3B	434,000	3,283,400	1483.634	-1020.228	132.8	40.5	11	3.4	209.9	372	23.9	7.3	-68.1	-8.58	EXP	Yes
	No. 4 Power Boiler	14	PB4B	434,000	3,283,400	1483.634	-1020.228	122.0	37.2	4	1.2	398.9	477	47.7	14.5	-358.7	-45.20	EXP	Yes
	No. 1 Smelt Dissolving Tank		SDT1B	434,000	3,283,400	1483.634	-1020.228	100.0	30.5	2	0.8	199.1	366	24.7	7.5	-1.0	-0.13	EXP	Yes
	No. 2 Smelt Dissolving Tank		SDT2B	434,000	3,283,400	1483.634	-1020.228	100.0	30.5	3	0.9	215.3	375	31.2	9.5	-1.4	-0.18	EXP	Yes
	No. 3 Smelt Dissolving Tank		SDT3B	434,000	3,283,400	1483.634	-1020.228	108.9	33.2	2	0.8	204.5	369	11.7	3.6	-1.4	-0.18	EXP	Yes
	No. 4 Smelt Dissolving Tank		SDT4B	434,000	3,283,400	1483.634	-1020.228	206.0	62.8	5	1.5	163.1	346	27.1	8.3	-5.6	-0.71	EXP	Yes
			SDT1234B	434,000	3,283,400	1483.634	-1020.228	100.0	30.5	2	0.8	199.1	366	24.7	7.5	-9.5	-1.20	EXP	Yes
	No. 1 Lime Kiln		LK1B	434,000	3,283,400	1483.634	-1020.228	49.9	15.2	4	1.3	262.1	401	17.2	5.2	-1.9	-0.24	EXP	Yes
	No. 2 Lime Kiln		LK2B	434,000	3,283,400	1483.634	-1020.228	52.2	15.9	6	1.7	154.1	341	35.0	10.7	-1.9	-0.24	EXP	Yes
	No. 3 Lime Kiln		LK3B	434,000	3,283,400	1483.634	-1020.228	52.2	15.9	6	1.7	155.9	342	27.8	8.5	-3.8	-0.48	EXP	Yes
	No. 4 Lime Kiln		LK4B	434,000	3,283,400	1483.634	-1020.228	148.9	45.4	4	1.3	172.1	351	54.0	16.5	-11.1	-1.40	EXP	Yes
			LK1234B	434,000	3,283,400	1483.634	-1020.228	49.9	15.2	4	1.3	262.1	401	17.2	5.2	-18.7	-2.36	EXP	Yes

TABLE FDEP-1A.1b

SUMMARY OF SO_2 SOURCES INCLUDED IN THE AIR MODELING FOR THE PSD CLASS I INCREMENT CONSUMPTION ANALYSES AT THE CHASSAHOWITZKA NWA

FPL GLADES POWER PARK

Facility	Facility Name		CALPUFF	UTM Location		LCC Location		Stack Parameters								SO_2 Emission			Modeled
				X	Y	X	Y	Height		Diameter		Temperature		Velocity		Rate		PSD Source? *	PSD
ID	Emission Unit Description	EU ID	ID Name	(m)	(m)	(km)	(km)	ft	m	ft	m	°F	K	ft/s	m/s	(lb/hr)	(g/sec)	(EXP/CON)	Source?
0190007	Iluka Resources, Inc.																		
	#1 Dryer aka Primary Dryer w/cyclone for product recovery	1	IR1D	432,400	3,304,200	1478.402	-999.806	34	10.4	2.8	0.9	308	426	78.0	23.8	39.1	4.93	CON	Yes
	#2 Dryer (Zircon Sand) w/Cylone for product recovery	2	IR2D	432,400	3,304,200	1478.402	-999.806	46	14.0	1.1	0.3	323	435	63.1	19.2	7.49	0.94	CON	Yes
	Zircon Calciner With Cyclone For Product Recovery	3	IRZC	432,400	3,304,200	1478.402	-999.806	46	14.0	1.1	0.3	415	486	50.9	15.5	9.52	1.20	CON	Yes
			IRINC	432,400	3,304,200	1478.402	-999.806	34	10.4	2.8	0.9	308	426	78.0	23.8	56.11	7.07	CON	Yes
0310157	Gerdau Ameristeel																		
			EAFBH1	405,700	3,350,000	1443.972	-958.907	110	33.5	12	3.7	230	383	55.2	16.8	16.0	2.02	CON	Yes
			EAFBH2	405,700	3,350,000	1443.972	-958.907	110	33.5	12	3.7	230	383	55.2	16.8	16.0	2.02	CON	Yes
			REHEATN	405,700	3,350,000	1443.972	-958.907	66	20.1	5.8	1.8	480	522	45.0	13.7	0.16	0.02	CON	Yes
			GERAMG1	405,700	3,350,000	1443.972	-958.907	110	33.5	12	3.7	230	383	55.2	16.8	32.2	4.05	CON	Yes
			ST12	405,700	3,350,000	1443.972	-958.907	115	35.1	10	3.0	230	383	64.8	19.8	-10.16	-1.28	EXP	Yes
			ST34	405,700	3,350,000	1443.972	-958.907	115	35.1	10	3.0	230	383	67.9	20.7	-1.11	-0.14	EXP	Yes
			REHEAT	405,700	3,350,000	1443.972	-958.907	160	48.8	6.9	2.1	900	755	19.5	5.9	-0.054	-0.01	EXP	Yes
			GERAMG2	405,700	3,350,000	1443.972	-958.907	115	35.1	10	3.0	230	383	64.8	19.8	-11.324	-1.43	EXP	Yes
0310485	JEA Brandy Branch																		
			S1NG	408,800	3,354,500	1446.252	-953.896	190	57.9	18	5.5	266	403	69.8	21.3	32.7	4.12	CON	Yes
			S2NG	408,800	3,354,500	1446.252	-953.896	190	57.9	18	5.5	266	403	69.8	21.3	32.7	4.12	CON	Yes
			S3FO	408,800	3,354,500	1446.252	-953.896	190	57.9	18	5.5	266	403	69.8	21.3	32.7	4.12	CON	Yes
			JEABB	408,800	3,354,500	1446.252	-953.896	190	57.9	18	5.5	266	403	69.8	21.3	98.1	12.36	CON	Yes
	PCS																		
			SULACC&D	328300	3368800	1,364.180	-953.606	150	45.7	5.2152	1.59	181.13	356	94.136	28.7	766.7	96.60	CON	Yes
			SULACE&F	328300	3368800	1,364.180	-953.606	200	61.0	9.512	2.9	181.13	356	30.504	9.3	833.3	105.00	CON	Yes
			AUXBLRE	328300	3368800	1,364.180	-953.606	50	15.2	5.248	1.6	310.73	428	52.152	15.9	170.6	21.50	CON	Yes
			AUXBLRB	328300	3368800	1,364.180	-953.606	35	10.7	4.7888	1.46	382.73	468	31.16	9.5	174.6	22.00	CON	Yes
			AUXBLRC&	328300	3368800	1,364.180	-953.606	104	31.7	6.4944	1.98	382.73	468	49.856	15.2	332.4	41.88	CON	Yes
			DAP2ZTR	328300	3368800	1,364.180	-953.606	140	42.7	8.0032	2.44	125.33	325	42.968	13.1	5.5	0.69	CON	Yes
			SULACA&B	328300	3368800	1,364.180	-953.606	200	61.0	5.904	1.8	170.33	350	50.84	15.5	-2416.7	-304.50	EXP	Yes
			SULACC&D	328300	3368800	1,364.180	-953.606	150	45.7	5.2152	1.59	181.13	356	94.136	28.7	-600.0	-75.60	EXP	Yes

* EXP = PSD expanding source.
CON = PSD consuming source.
NO = Baseline Source, does not affect PSD increment.

TABLE FDEP-1A.2
MAXIMUM MERCURY DEPOSITION PREDICTED FOR THE PROJECT AT THE EVERGLADES NATIONAL PARK USING EPA VERSION OF THE CALPUFF MODEL

		Predicted Mercury Deposition		
		Average		
Year		**($g/m^2/s$)**	**($g/m^2/yr$)[a]**	
2001	Total	7.63E-17	2.41E-09	
	Wet	2.06E-17	6.48E-10	27%
	Dry	5.57E-17	1.76E-09	73%
2002	Total	1.55E-16	4.88E-09	
	Wet	7.31E-17	2.30E-09	47%
	Dry	8.18E-17	2.58E-09	53%
2003	Total	1.23E-16	3.87E-09	
	Wet	3.05E-17	9.62E-10	25%
	Dry	9.22E-17	2.91E-09	75%
Average	Total	1.18E-16	3.72E-09	
	Wet	4.14E-17	1.31E-09	35%
	Dry	7.66E-17	2.41E-09	65%

[a] Conversion factor is used to convert $g/m^2/s$ to $g/m^2/yr$ with the following units:

$g/m^2/s$ x 3,600 sec/hr
x 8,760 $g/m^2/yr$
or
$g/m^2/s$ x 3.154E+07 = $g/m^2/yr$

ATTACHMENT FDEP-2A

EPA IGCC LETTER

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

DEC 13 2005

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

Mr. Paul Plath
Senior Partner
E3 Consulting, LLC
3333 South Bannock Street, Suite 740
Englewood, Colorado 80110

Subject: Best Available Control Technology Requirements for Proposed Coal-Fired Power Plant Projects

Dear Mr. Plath:

Your firm's letter to me dated February 28, 2005, from D. Edward Settle, asks for the U.S. Environmental Protection Agency's (EPA) position regarding whether an analysis of Best Available Control Technology (BACT) for proposed coal-fired power plants must specifically include evaluation of alternative designs of coal-fueled processes such as integrated gasification combined cycle (IGCC). Generally, the Clean Air Act (CAA) requires an applicant to apply BACT as a condition for issuance of a prevention of significant deterioration (PSD) construction permit in an attainment area. This response provides EPA's view of how the CAA should be interpreted and EPA regulations applied under the particular circumstances presented based on prior EPA policy statements and adjudicatory decisions.

There are two different parts of the PSD permitting process where consideration of alternative designs or production processes may occur. One part is under Section 165(a)(2) where it is required that the permitting authority allow an "opportunity for interested persons ... to appear and submit written or oral presentations on the air quality impact of such source, ***alternatives thereto***, control technology requirements, and other appropriate considerations" (emphasis added). The other part is section 165(a)(4), which requires that a proposed facility subject to PSD apply BACT. In Section 169(3) of the CAA, BACT is defined as "an emission limitation based on the maximum degree of reduction ... which the permitting authority ... determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant."

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EPA's view is that, through this language, Congress distinguished "production processes and available methods, systems and techniques" that are potentially applicable to a particular type of facility and should be considered in the analysis of BACT from "alternatives" to the proposed source that would wholly replace the proposed facility with a different type of facility. Although we read this language to draw such a distinction, in practice, it is often not clear when another production process should be considered to fit within the BACT definition and when it should be considered an alternative to the proposed source. This distinction is especially difficult to make for coal gasification because the definition of BACT includes "innovative fuel combustion techniques" in a list of examples of production processes or available methods, systems, or techniques to be considered in the BACT analysis. However, even assuming that coal gasification were in all respects an innovative fuel combustion technique for producing electricity from coal, we do not believe Congress intended for an "innovative fuel combustion technique" to be considered in the BACT review when application of such a technique would redesign the proposed source to the point that it becomes an alternative type of facility, which, as discussed below, we believe would be the case if IGCC were applied to a proposed SCPC unit.

As noted in prior EPA decisions and guidance, EPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. For example, we do not require applicants proposing to construct a coal-fired steam electric generator to consider building a natural gas-fired combustion turbine as part of a BACT analysis, even though the turbine may be inherently less polluting per unit product (in this case electricity). In re SEI Birchwood Inc, 5 E.A.D. 25 (1994); In re Old Dominion Electric Cooperative, 3 E.A.D. 779 (1992).

Therefore, the question in this instance is whether IGCC results in a redefinition of the basic design of the source if the permittee is proposing to build a supercritical pulverized coal (SCPC) unit. In this situation, EPA's view is that applying the IGCC technology would fundamentally change the scope of the project and redefine the basic design of the proposed source. Portions of an IGCC process are very similar to existing power generation designs that we have previously identified as a redefinition of the basic design of source when an applicant proposed to construct a pulverized coal-fired boiler. The combined cycle generation power block of an IGCC employs the same turbine and heat recovery technology that is used to generate electricity with natural gas at other electrical generation facilities. As noted above, we do not require applicants proposing to construct a coal-fired steam electric generator to consider building a gas-fired combustion turbine as part of a BACT analysis. Furthermore, the core process of gasification at an IGCC facility is more akin to technology employed in the refinery and chemical manufacturing industries than technologies generally in use in power generation (i.e., controlled chemical reaction versus a true combustion process). This technology would necessitate different types of expertise on the part of the company and its employees to produce the desired product (electricity) than the typical SCPC unit. Therefore, where an applicant proposes to construct a SCPC unit, we believe the IGCC process would redefine the basic design of the source being proposed.

Accordingly, consistent with our established BACT policy, we would not require an applicant to consider IGCC in a BACT analysis for a SCPC unit. Thus, for such a facility, we would not include IGCC in the list of potentially applicable control options that is compiled in the first step of a top-down BACT analysis. Instead, we believe that an IGCC facility is an alternative to an SCPC facility and therefore it is most appropriately considered under Section 165(a)(2) of the CAA rather than section 165(a)(4).

Your letter did not specifically request guidance on whether IGCC should be considered in a LAER analysis for a SCPC, but I am taking this opportunity to address the issue. As with BACT, an applicant must generally comply with LAER as a condition for issuance of a nonattainment new source review (NSR) permit in a nonattainment area. Section 173(a)(5) of the CAA requires an applicant to conduct, "an analysis of ***alternative sites, sizes, production processes*** and environmental control techniques for such proposed source." (emphasis added). Because we believe IGCC results in a redefinition of the source in this situation, it should not be considered in a LAER analysis for a SCPC unit. Nonetheless, we believe that the technology should be considered under Section 173(a)(5) when an SCPC unit is proposed in nonattainment areas.

I trust that this response addresses the issues raised in your letter.

Sincerely,

Stephen D. Page

Stephen D. Page
Director
Office of Air Quality, Planning
and Standards

ATTACHMENT FDEP-2B

CLEAN COAL TECHNOLOGY SELECTION STUDY

Clean Coal Technology Selection Study

Final Report

January 2007

BLACK & VEATCH
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ENERGY WATER INFORMATION GOVERNMENT

FPL.

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Acronyms

AFBC	Atmospheric Fluidized Bed Combustion
AGR	Acid Gas Removal
AQCS	Air Quality Control Systems
ASML	Above Mean Sea Level
ASU	Air Separation Unit
BACT	Best Available Control Technology
BFP	Boiler Feed Pump
Ca/S	Calcium to Sulfur
CaO	Calcium Oxide
CaS	Calcium Sulfide
$CaSO_4$	Calcium Sulfate
CCPI	Clean Coal Power Initiative
CCRB	Clean Coal Review Board
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COP	ConocoPhillips
COS	Carbonyl Sulfide
CTG	Combustion Turbine Generator
DA	Deaerator
DCS	Distributed Control System
DLN	Dry Low NO_x
DOE	Department of Energy
EIS	Environmental Impact Statement
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FBC	Fluidized Bed Combustion
FEED	Front End Engineering Design
FGR	Flue Gas Recirculation
FPL	Florida Power & Light
FWH	Feedwater Heater
FGPP	FPL Glades Power Park

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GE	General Electric
GEC	Gasification Engineering Corporation
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HCl	Hydrogen Chloride
HCN	Hydrogen Cyanide
HHV	Higher Heating Value
HP	High-Pressure
HRSG	Heat Recovery Steam Generator
IDC	Interest During Construction
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate-Pressure
ISO	International Organization for Standardization
KBR	Kellogg Brown and Root
LHV	Lower Heating Value
LP	Low-Pressure
MDEA	Methyl Diethanol Amine
MHI	Mitsubishi Heavy Industries
NEPA	National Environmental Policy Act
NGCC	Natural Gas Combined Cycle
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standards
O&M	Operations and Maintenance
OFA	Overfire Air
OP	Over Pressure
OUC	Orlando Utilities Commission
PC	Pulverized Coal
Petcoke	Petroleum Coke
PJFF	Pulse Jet Fabric Filter
PM_{10}	Particulate Matter (filterable 10 microns and less)
PRB	Powder River Basin
PSDF	Power Systems Development Facility
PUCO	Public Utilities Commission of Ohio
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber

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SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SPC	Subcritical Pulverized Coal
SCPC	Supercritical Pulverized Coal
SPG	Siemens Power Generation
STG	Steam Turbine Generator
SWEPCO	Southwestern Electric Power Company
TC4F	Tandem-Compound Four Flow
TRIG	Transport Reactor Integrated Gasification
US	United States
USCPC	Ultra Supercritical Pulverized Coal
VWO	Valves Wide Open

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Units of Measure

¢	Cents
$	Dollar
%	Percent
% wt	Percent weight
° F	Degrees Fahrenheit
Btu	British thermal unit
ft	foot
ft^3	cubic feet
h	hour
in. HgA	inches of mercury, absolute
kW	kilowatt
lb	pound
ltpd	long tons per day (2,240 lb/day)
m^3	cubic meters
MBtu	million British thermal unit
mg	milligram
MW	megawatt
MWh	megawatt-hour
N	Newton
ppb	parts per billion
ppm	parts per million
ppmvd	parts per million, volumetric dry
psia	pounds per square inch, absolute
scf	standard cubic feet
sec	second
stpd	short tons per day (2,000 lb/day)
tpd	tons per day
yr	year

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1.0 Executive Summary

1.1 Introduction

This study is in connection with Florida Power & Light's (FPL) generation expansion project investigations for the addition of a nominal 2,000 MW of capacity. FPL has previously identified a need to diversify its fuel consumption. Therefore, this study investigates only coal-fueled technologies. The study compared subcritical pulverized coal (SPC), ultrasupercritical pulverized coal (USCPC), circulating fluidized bed (CFB), and integrated gasification combined cycle (IGCC). These baseload pulverized coal (PC), CFB, and IGCC technologies comprise the clean coal options available for consideration to meet FPL's generation expansion project needs in the 2012 to 2014 time period.

This study provides technology descriptions, plant descriptions, and screening level estimates of performance, capital costs, and operations and maintenance (O&M) costs for the various power generation technologies considered. Performance and cost estimates were based on assumptions made by Black & Veatch, in conjunction with FPL, for site and ambient conditions, cycle arrangements, air quality control systems (AQCS), and analysis of the proposed fuel. A busbar economic analysis was also performed to compare the technologies.

1.2 Plant Descriptions

Black & Veatch developed screening level performance and cost estimates for each of the technologies: SPC, USCPC, CFB, and IGCC. The required capacity would be met by installing blocks of power at the site to obtain a nominal 2,000 MW net. The fuels used for the performance and cost estimates consisted of blends of Central Appalachian coal, Colombian coal, and petroleum coke (petcoke). The PC and CFB cases utilized a blend of 40 percent Central Appalachian coal, 40 percent Colombian coal, and 20 percent petcoke – referred to as the AQCS Blend. The IGCC case utilized a blend of 25 percent Central Appalachian coal, 25 percent Colombian coal, and 50 percent petcoke – referred to as the IGCC Blend. All blend percentages are by weight. The technologies, plant sizes, and arrangements that were considered for this study are shown in Table 1-1.

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Table 1-1. Summary of Power Generation Technologies					
Case	**Technology Type**	**Single Unit Output, MW**	**Net Plant Output, MW**	**Configuration**	**Fuel Supply**
1	SPC	500	2,000	4 Boilers 4 STGs	AQCS Blend
2	USCPC	980	1,960	2 Boilers 2 STGs	AQCS Blend
3	CFB	497	1,988	8 Boilers 4 STGs	AQCS Blend
4	IGCC	940	1,880	6 GE Radiant Gasifiers 6 CTGs 6 HRSGs 2 STGs	IGCC Blend

STG–Steam Turbine Generator
CTG–Combustion Turbine Generator
HRSG–Heat Recovery Steam Generator

1.3 Overall Assumptions

For the basis of the performance estimates, the site conditions of the proposed greenfield FPL Glades Power Park (FGPP) in Glades County, Moore Haven, Florida were used. The site conditions were provided to Black & Veatch by FPL. Performance estimates were developed for both the hot day and the average day ambient conditions. Following are the overall assumptions, which were consistent among all of the technologies:

- Elevation–20 feet above mean sea level (ASML).
- Ambient barometric pressure–14.67 psia.
- Hot day ambient conditions:
  - Dry-bulb temperature–95° F.
  - Relative humidity–50 percent.
- Average day ambient conditions:
  - Dry-bulb temperature–75° F.
  - Relative humidity–60 percent.
- The assumed fuel is a blend of three different fuels. The ultimate analysis of the AQCS and IGCC Blend fuels (which were used to determine performance and cost estimates) is provided in Table 1-2.

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- AQCS equipment was selected to develop performance and cost estimates, based on Black & Veatch experience. Actual AQCS equipment would be selected to comply with federal New Source Performance Standards (NSPS), be subject to a Best Available Control Technology (BACT) review, and achieve the emission levels shown in Table 5-4.
- Condenser performance was based on Black & Veatch experience. The expected condenser back pressures were supplied for hot and average day ambient conditions.

Table 1-2. Ultimate Fuel Analysis

Fuel	AQCS Blend	IGCC Blend
Carbon, % wt	69.85	73.28
Sulfur, % wt	1.98	3.77
Oxygen, % wt	5.51	3.74
Hydrogen, % wt	4.35	3.96
Nitrogen, % wt	1.37	1.46
Chlorine, % wt	0.07	0.05
Ash, % wt	7.68	4.99
Water, % wt	9.18	8.74
HHV, Btu/lbm	12,300	12,800

HHV–Higher Heating Value.

1.4 Performance Estimates

1.4.1 PC and CFB Cases

The cases were evaluated on a consistent basis to show the effects of technology selection on project performance. The performance estimates were generated for single units that would be installed at a multiple unit greenfield site. Full-load performance estimates for each of the PC and CFB cases are presented in Table 1-3.

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Table 1-3. PC and CFB Coal Performance Estimates, per Unit

Technology Fuel	SPC AQCS Blend	USCPC AQCS Blend	CFB AQCS Blend
Performance on Average Ambient Day at 20 ft ASML, Clean and New Equipment			
Steam Conditions, psia/° F/° F	2,415/1,050/1,050	3,715/1,112/1,130	2,415/1,050/1,050
Fuel Input, Mbtu/h	4,600	8,480	4,730
Boiler Efficiency (HHV), percent	88.9	88.9	87.0
Heat to Steam (HHV), Mbtu/h	4,090	7,545	4,200
Gross Single Unit Output, MW	550	1,054	556
Total Auxiliary Load, MW	50	74	59
Net Single Unit Output, MW	500	980	497
Gross Turbine Heat Rate, Btu/kWh	7,450	7,140	7,540
Condenser Pressure, in. HgA	2.2	2.1/1.7	2.2
NPHR (HHV), Btu/kWh	9,210	8,660	9,510
Net Plant Efficiency (HHV), percent	37.0	39.4	35.9
Performance on Hot Day at 20 ft ASML, Clean and New Equipment			
Net Single Unit Output, MW	494	976	491
NPHR (HHV), Btu/kWh	9,340	8,690	9,640
Performance On Average Ambient Day at 20 ft ASML, Maximum Degradation (1.0% heat rate and 1.0% net plant output)			
Net Single Unit Output, MW	495	970	492
NPHR (HHV), Btu/kWh	9,300	8,750	9,610

Note:
USCPC option has dual condensers, therefore both pressures are listed.
No margins were applied to performance estimates.

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1.4.2 IGCC Cases

Full-load performance estimates were developed for the IGCC case. The IGCC case was evaluated on a consistent basis with the PC and CFB cases with respect to site and ambient conditions to show the effects of technology selection on project performance. Performance estimates for the IGCC case using GE Radiant gasifiers are presented in Table 1-4. IGCC performance is presented in a separate table from the PC and CFB cases because the performance parameters are slightly different.

Table 1-4. GE Radiant IGCC Performance Estimates, per Unit

Fuel	IGCC Blend
Combined Cycle Configuration	3 x 1 GE 7FB
Performance on Average Day at 20 ft ASML, Clean and New Equipment	
Coal to Gasifiers, MBtu/h	8,400
Gasifier Cold Gas Efficiency, % (Clean Syngas HHV/Coal HHVx100)	74
CTG Heat Rate (LHV), Btu/kWh	8,370
CTG(s) Gross Power, MW	687
Steam Turbine Gross Power, MW	451
Syngas Expander Power, MW	5
Total Gross Power, MW	1,143
Aux. Power Consumption, MW	203
Net Power, MW	940
Net Plant Heat Rate (HHV), Btu/kWh	8,990
Net Plant Efficiency (HHV), Btu/kWh	38.0
Performance on Hot Day at 20 ft ASML, Clean and New Equipment	
Net Power, MW	902
Net Plant Heat Rate (HHV), Btu/kWh	9,360
Performance on Average Day at 20 ft ASML, Maximum Degradation (2.5% heat rate and 2.5% net power output)	
Net Power, MW	917
Net Plant Heat Rate (HHV), Btu/kWh	9,215

Note:
Based on publicly available data from technology vendor.
No margins were applied to performance estimates.

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1.5 Cost Estimates

1.5.1 Capital Costs

Screening level overnight capital cost estimates for the four technologies were estimated on an engineering, procurement, and construction (EPC) basis, exclusive of Owner's costs. The estimates are expressed in 2006 United States (US) dollars and are included in Table 1-5. The cost estimate includes estimated costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis. The estimates were based on Black & Veatch proprietary estimating templates and experience. These estimates are screening-level estimates prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc. Cost estimates are made using consistent methodology between technologies, so while the absolute cost estimates are expected to vary within a band of accuracy, the relative accuracy between technologies is better.

Capital cost estimates for all power generation technologies are exhibiting considerable upward trends. Market pricing of technology components, coupled with commodity and labor demand worldwide, is rapidly escalating capital costs. These costs increases are not confined to any particular generation technology; they apply across the industry.

Table 1-5. EPC Capital Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
EPC Cost, 2006$MM	3,078	2,646	3,240	3,541
Unit EPC Cost, 2006$/kW	**1,540**	**1,350**	**1,630**	**1,880**
Escalation to 2012$	490	421	516	564
Subtotal - EPC Cost 2012$	*3,568*	*3,067*	*3,756*	*4,105*
Owner's Costs, 2012$	1,218	1,153	1,236	1,411
IDC, 2012$	1,063	914	1,119	1,223
Project Cost, 2012$	*5,849*	*5,134*	*6,111*	*6,739*
Unit EPC Cost, 2012$/kW	**2,925**	**2,619**	**3,074**	**3,585**

1.5.2 Nonfuel O&M Costs

Preliminary screening level estimates of O&M expenses for the technologies were developed. The O&M estimates were derived from other detailed estimates developed by

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Black & Veatch, based on vendor estimates and recommendations; actual performance information gathered from in-service units; and representative costs for staffing, materials, and supplies. The nonfuel O&M cost estimates, including fixed and variable costs, are shown in Table 1-6.

Table 1-6. O&M Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
Capacity Factor, percent	92.0	92.0	88.0	80.0
Annual Generation, GWh	16,100	15,800	15,300	13,200
Fixed Costs, 2006$, (1,000s)	35,780	27,500	38,800	47,810
Fixed Costs, 2006$/kW	17.89	14.03	19.54	25.43
Variable Costs, 2006$ (1,000s)	45,130	47,500	68,000	80,120
Variable Costs, 2006$/MWh	2.94	2.86	4.44	6.07
Fixed Costs, 2012$, (1,000s)	41,480	31,870	45,050	55,420
Fixed Costs, 2012$/kW	20.74	16.26	22.66	29.48
Variable Costs, 2012$ (1,000s)	54,900	52,300	78,600	92,930
Variable Costs, 2012$/MWh	3.41	3.31	5.14	7.04

1.6 Busbar Cost Analysis

A levelized busbar cost analysis was performed using several sets of data. These include:

- Economic criteria provided by FPL
- Fuel forecasts provided by FPL
- Performance estimates for the PC, CFB, and IGCC cases listed in Table 1-3 and Table 1-4.
- EPC capital cost estimates listed in Table 1-5,
- O&M cost estimates listed in Table 1-6.

The PC and CFB cases were run with 40 year book and 20 year tax lives. The IGCC case was run with 25 year book and 20 tax lives.

Performance was based on the annual average day conditions. The capacity factors for the PC, CFB, and IGCC units were assumed to be 92, 88, and 80 percent, respectively.

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The results of the busbar analysis are provided in Table 1-7. Results are provided in 2012$. Several cases were run:

- Degraded performance at average ambient conditions with no emissions allowance cost included.
- New and clean performance at average ambient conditions with no emissions allowance cost included.
- Degraded performance at average ambient conditions with emissions allowance cost included for oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and mercury (Hg). Emission allowance costs were estimated by multiplying a forecasted allowance cost by the total annual emissions of each pollutant based on the assumed control limits minus annual emission allocations for FGPP.
- New and clean performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, and Hg.
- Degraded performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, Hg, and carbon dioxide (CO_2) using the 2005 Bingaman carbon tax proposal. No carbon capture was included.

From the analysis, the USCPC unit is the most cost effective technology.

Table 1-7. Busbar Cost Analysis Results, ¢/kWh

Case	SPC	USCPC	CFB	IGCC
Degraded performance, w/o emissions	9.56	8.63	10.54	12.69
New and clean performance, w/o emissions	9.47	8.54	10.43	12.38
Degraded performance, w/ emissions	9.68	8.74	10.66	12.81
New and clean performance, w/ emissions	9.58	8.65	10.56	12.50
Degraded performance, w/ emissions including CO_2	10.96	9.94	11.99	14.00

Note: Results were based on economic criteria from Table 7-1, fuel forecasts from Table 7-2, and the inputs from Table 7-3. These results are based on the maximum assumed capacity factors at average ambient conditions. Results are based on 2012 cost estimates.

Three charts are provided to illustrate sensitivities of the busbar cost analysis. Figure 1-1 shows a breakdown of the components of the base case busbar cost without emissions allowances. Fuel and capital requirements make up the majority of the total busbar costs. Variations in these two cost categories will have the largest effect on the

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estimated busbar cost for any technology. Figures 1-2 and 1-3 are similar to Figure 1-1, but show the effect of adding the cost of emissions allowances. Figure 1-2 shows the incremental cost of adding allowance costs for NO_x, SO_2 and Hg. It can be seen that variations in emissions translate to minimal cost variations between the technologies. Figure 1-3 shows that the effect of adding CO_2 allowances (using the Bingaman case with no carbon capture). The carbon tax causes a noticeable increase to the absolute busbar costs, but because CO_2 emissions are relatively equal between technologies there is no effect on the rank order of busbar costs. All of the cases illustrated are based on degraded performance.

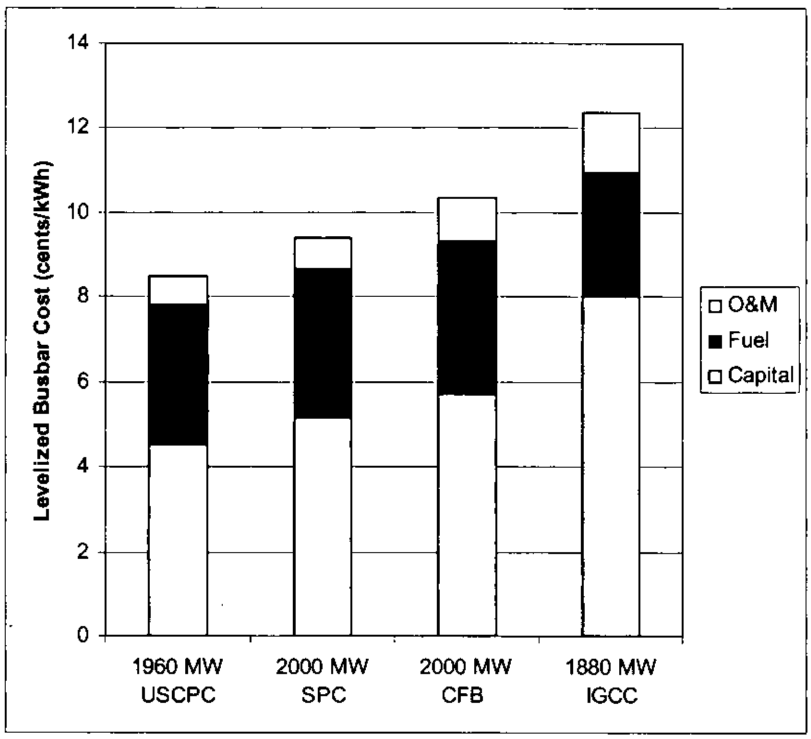

Figure 1-1. Busbar Cost Component Analysis without Emissions

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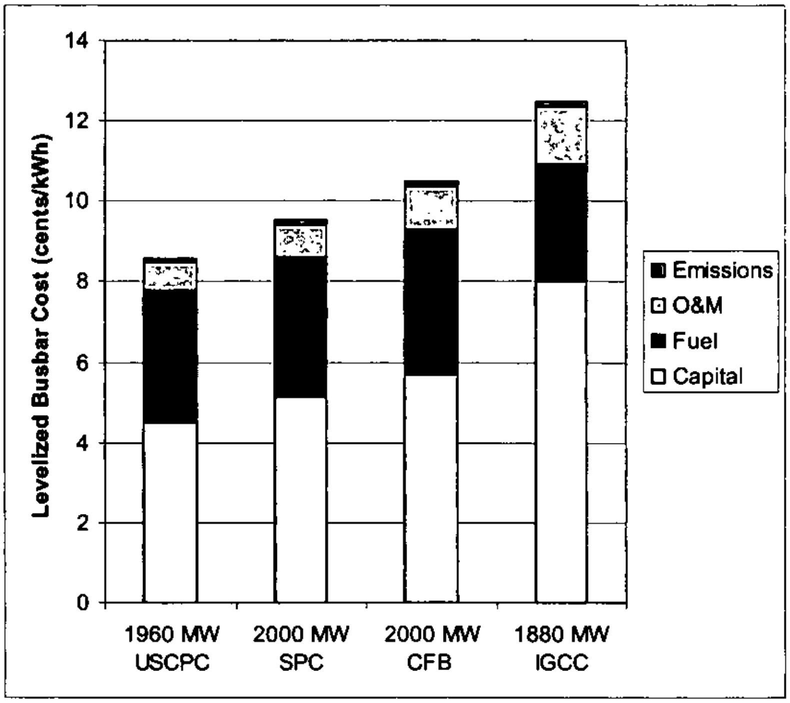

Figure 1-2. Busbar Cost Component Analysis with Emissions

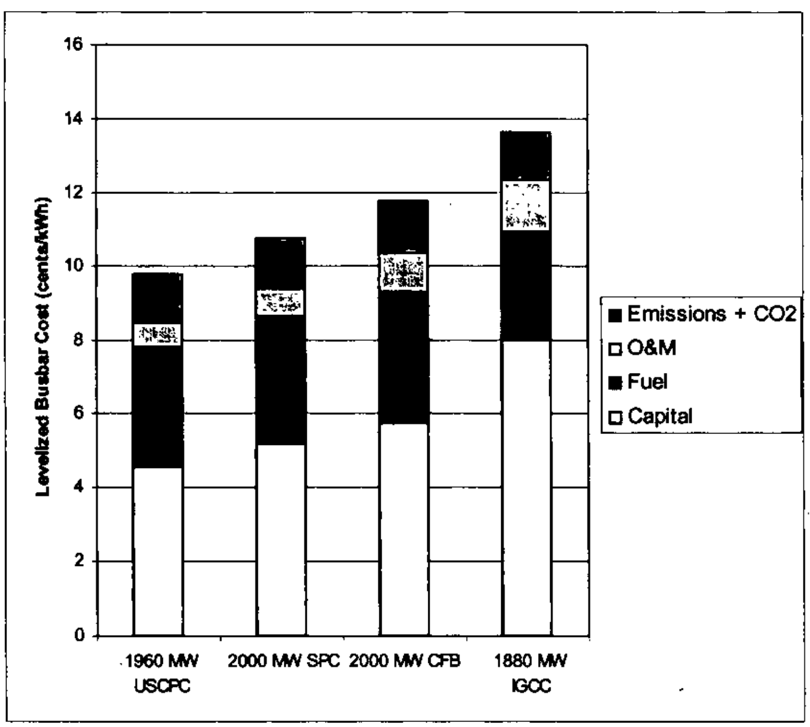

Figure 1-3. Busbar Cost Component Analysis with CO_2

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A sensitivity case was run that included potential costs of carbon capture. There have been many studies performed by other parties to quantify the cost of capturing carbon. Because study of the potential cost of carbon capture was not a focus of this effort, high level assessments have been made to provide a representation of the cost of carbon capture and show the relative effect of this added cost on the economic comparison between technologies.

A review of recent literature, including the US EPA "Environmental Footprints and Cost of Coal-Based Integrated Gasification and Pulverized Coal Technologies", the Alstom chilled ammonia position paper, and Black & Veatch work indicates a probable range of carbon capture as shown in Table 1-8.

Table 1-8. Probable Carbon Capture Costs, \$/Avoided Ton CO_2.

Case	Low Cost	High Cost
Post-Combustion, 2006$	20	40
Pre-Combustion, 2006$	20	30

The cost range for pre-combustion is representative of current literature values published by technology neutral sources. The cost range for post-combustion uses Alstom's cost projection for their technology to establish the low value and then makes an assumption that the commercial cost could be 100 percent more for the high value. Estimated costs for other post combustion carbon capture systems published in other studies are higher than those published for this unique Alstom technology.

When these costs are added to the busbar cost analysis, with adjustments for output and net plant heat rate made as needed, the percentage increase of busbar cost over the base case analysis for new & clean conditions are as shown in Table 1-9.

Table 1-9. Probable Busbar Percentage Cost Increase with Carbon Capture and Emissions Allowances.

Case	Low Cost	High Cost
SPC	20	30
USCPC	20	30
CFB	20	30
IGCC	20	25

Note:
Assumes 90 percent carbon capture for conditions at average ambient temperatures compared to case with no emissions allowance costs. Includes emissions allowances for NO_x, SO_2, Hg, and emitted CO_2 using the 2005 McCain cost proposal.

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A sensitivity analysis was run to show the effect variations in capacity factor have on economic analysis outputs. Figures 1-4 and 1-5 show the variations in busbar cost in cents per unit of generation (¢/kWh) and net levelized annual cost in dollars per unit of net plant output ($/kW) versus annual capacity factor. The sensitivity analysis was run over a range of capacity factors, from 40 percent to the maximum for each technology. The net plant heat rate was kept constant for all capacity factors, assuming full load operation. While all of the technologies have dramatic changes in busbar and net levelized annual cost across the range of capacity factors, the rank order of costs does not vary with capacity factor.

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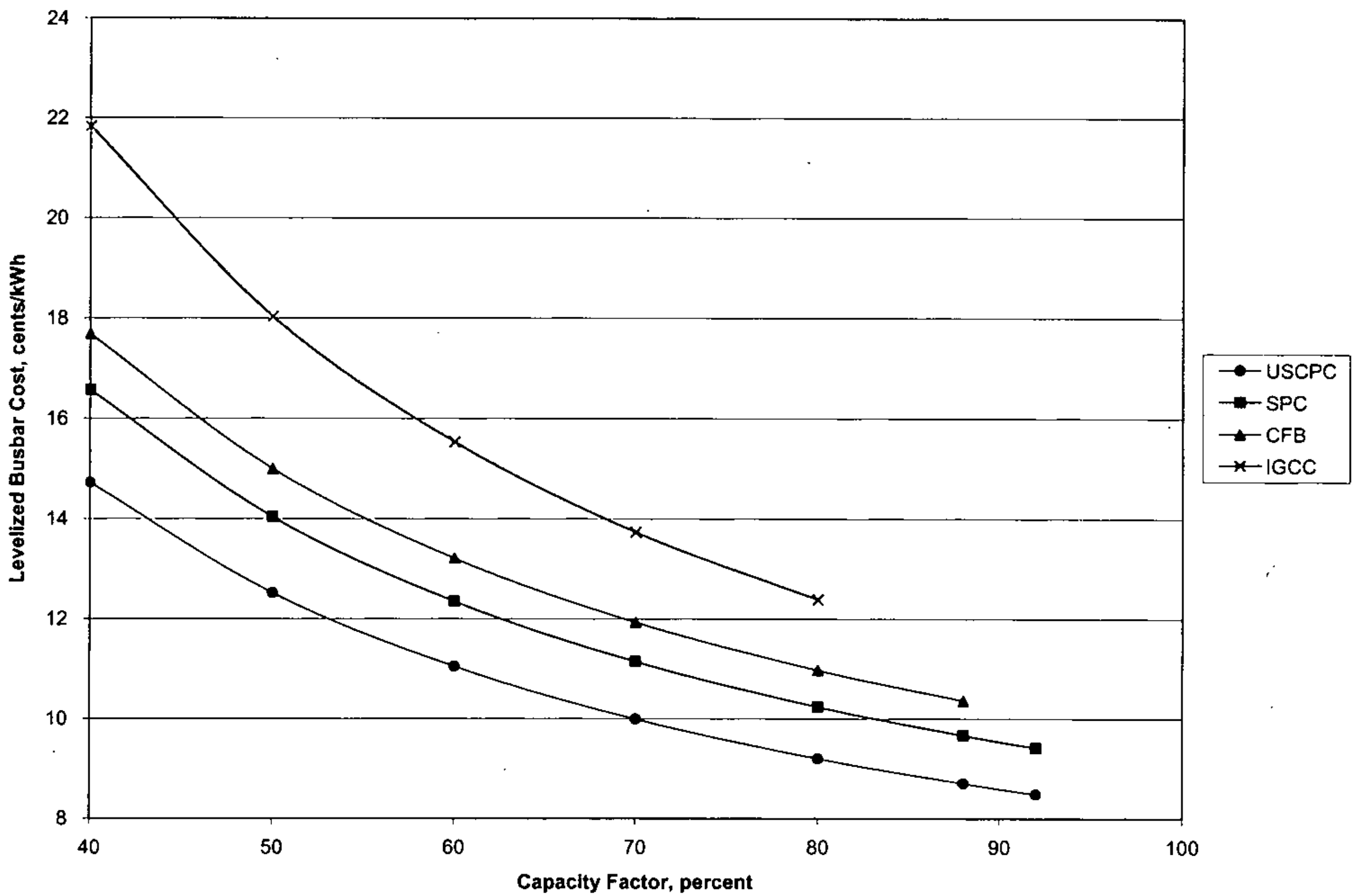

Figure 1-4. Busbar Cost Variation with Capacity Factor

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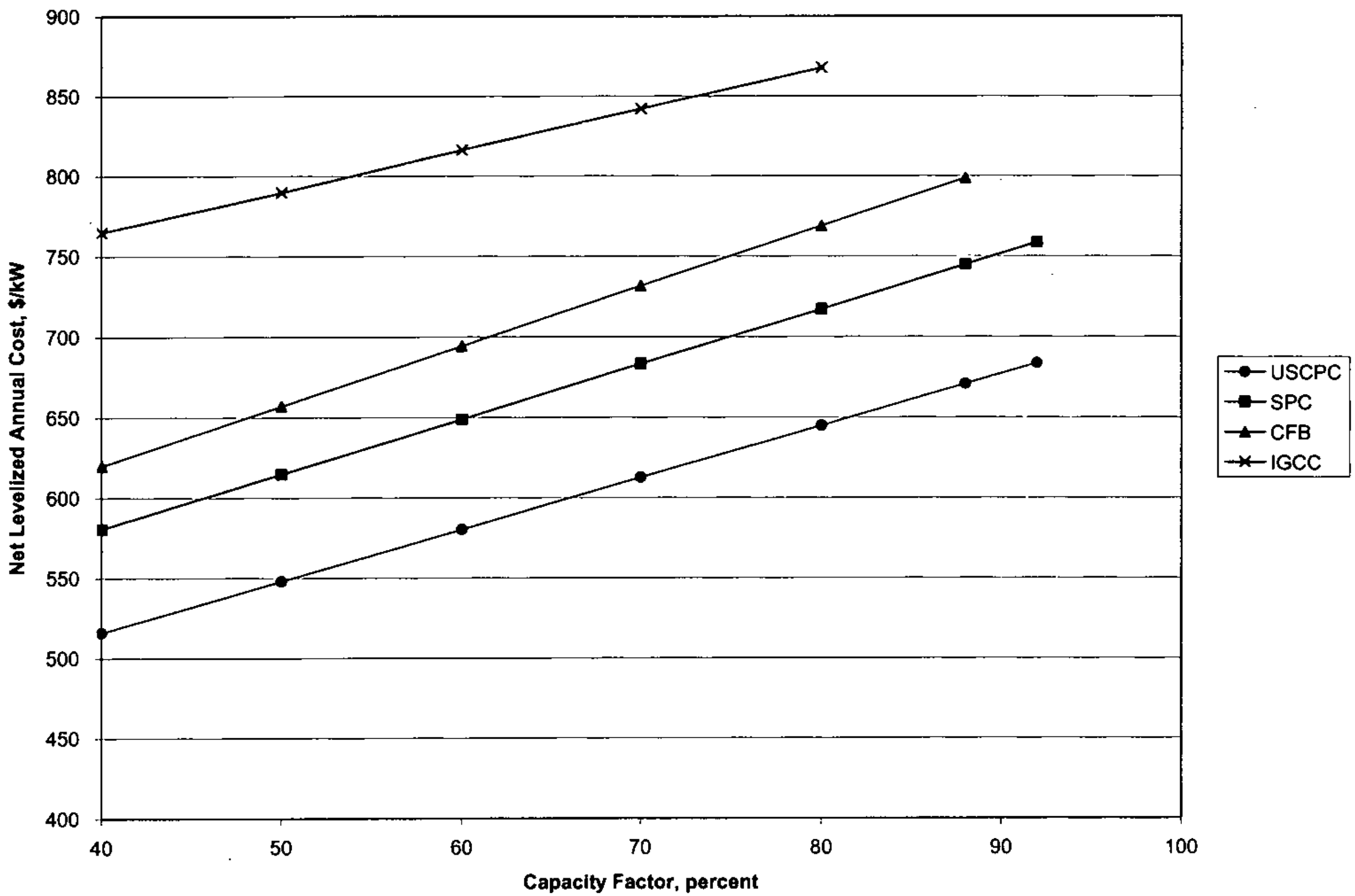

Figure 1-5. Net Levelized Annual Cost Variation with Capacity Factor

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1.7 Conclusions

This study made a comparison of performance and cost of four commercially available coal-fired power generation technologies. These were USCPC, SPC, CFB and IGCC. The estimates for performance were made using publicly available data and engineering data that has been collected by Black & Veatch and FPL. The results of the study are not intended to be absolute for any given technology but rather are intended to be accurate relative from one technology to another.

This study addresses technology risks known or assumed for each type of plant. Clearly PC plants are commercial and have been a dependable generation technology for years. The advancement of operation at ultrasupercritical steam conditions is somewhat new, but has been commercially demonstrated and proven around the world. CFB has also proven its dependability over the past two decades and is considered a mature technology. IGCC has been demonstrated on a commercial scale for over ten years. A second round of commercial scale IGCC plants is being planned currently. Many utilities will reserve decisions on making future IGCC installations until they have observed the installation and operation of these new plants.

Capital cost estimates for all power generation technologies are exhibiting considerable upward trends. Market pricing of technology components, coupled with commodity and labor demand worldwide, is rapidly escalating capital costs. These costs increases are not confined to any particular generation technology; they apply across the industry.

Based on the assumptions, conditions, and engineering estimates made in this study, the USCPC option is the preferred technology selection for the addition of a nominal 2,000 MW net output at the Glades site. The busbar cost of the SPC case, which is the second lowest busbar cost case, is nearly 10 percent more than USCPC. USCPC will have good environmental performance because of its high efficiency. Emissions of NO_x and PM will be very similar across all technologies. Sulfur emissions would be slightly lower for IGCC than the PC and CFB options, although start-up and shutdown flaring will reduce the potential benefit of IGCC. The lower expected reliability of IGCC, particularly in the first years of operation, could compromise FPL's ability to meet the baseload generation requirement and require FPL to run existing units at higher capacity factors.

For the 2012 to 2014 planning time period, USCPC will be the best technical and economic choice for installation of 2,000 MW of capacity at the Glades site.

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2.0 Introduction

This study is in connection with Florida Power & Light's (FPL) generation expansion project investigations for the addition of a nominal 2,000 MW of capacity. The objective of this technology assessment is to characterize the commercially available coal fired electric power generation technologies. The baseload coal technologies considered were SPC, USCPC, CFB, and IGCC. These options were selected as representative of the options that could meet FPL's clean coal capacity planning needs.

This study provides technology descriptions, plant descriptions and assumptions, and screening level estimates of performance, capital costs, and O&M costs for four coal power generation technologies. Full-load performance estimates were developed at both the hot day and average day ambient conditions.

Each of the cases considered would be located on a greenfield site at the proposed Florida Glades Power Park (FGPP) in Moore Haven, Florida. The required net capacity would be met by installing blocks of power to obtain a nominal 2,000 MW net at the plant boundary. The SPC unit would have a net capacity of 500 MW. The SPC units would be arranged in a four boiler-by-four steam turbine (4x4) configuration. This configuration would produce the required net capacity of 2,000 MW. Each SPC unit would have a net capacity of 980 MW; a 2x2 configuration would be used. Each CFB unit would have a 500 MW net capacity and would comprise two 250 MW CFB boilers and one 500 MW steam turbine. An 8x4 configuration would be required for the CFB case.

For the IGCC case, the nominal 2,000 MW project net capacity could be met by two 940 MW IGCC units. To obtain the 1,880 MW net capacity at the site boundary, six GE Radiant gasifiers would be used in two 3x3x3x1 configurations. The combined cycle configuration of the FGPP plant would consist of six combustion turbine generators (CTGs) whose exhaust heat would generate steam in six heat recovery steam generators (HRSGs). Steam produced in the HRSGs would then be expanded through two steam turbine generators (STGs).

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Each of the technologies considered would be fired by a blended fuel consisting of Central Appalachian coal, Colombian coal, and petcoke. A summarized list of the cases that were considered is shown in Table 2-1.

Table 2-1. Summary of Power Generation Technologies

Case	Technology Type	Single Unit Output, MW	Net Plant Output, MW	Configuration	Fuel Supply
1	SPC	500	2,000	4 Boilers 4 STGs	AQCS Blend
2	USCPC	980	1,960	2 Boilers 2 STGs	AQCS Blend
3	CFB	500	2,000	8 Boilers 4 STGs	AQCS Blend
4	IGCC	940	1,880	6 GE Gasifiers 6 CTGs 6 HRSGs 2 STGs	IGCC Blend

Assumptions were made for each technology, which addressed their configuration and AQCS. The AQCS for each technology were selected to comply with NSPS and recent BACT levels for criteria pollutants, including oxides of nitrogen (NO_x), sulfur dioxide (SO_2), filterable particulate matter of 10 microns or less (PM_{10}), and sulfuric acid mist (SAM). AQCS assumptions were made by FPL and are expected to be appropriate to control air emissions to the levels specified in Table 5-4.

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3.0 PC and CFB Technologies

This section contains a summary-level comparison of PC and CFB technologies, including review of technology experience in the United States and discussions of advanced PC steam conditions and issues related to scaling-up CFB unit sizes.

The function of a steam generator is to provide controlled release of heat from the fuel and efficient transfer of heat to the feedwater and steam. The transfer of heat produces main steam at the pressure and temperature required by the high-pressure (HP) turbine. Coal fired steam generator design has evolved into two basic combustion and heat transfer technologies. Suspension firing of coal in a PC unit and the combustion of crushed coal in a CFB unit are the predominant coal fired technologies in operation today.

3.1 Pulverized Coal

Coal is the most widely used fuel for the production of power, and most coal-burning power plants use PC boilers. PC units utilize a proven technology with a very high reliability level. These units have the advantage of being able to accommodate up to 1,300 MW, and the economies of scale can result in low busbar costs. PC units are relatively easy to operate and maintain.

New-generation PC boilers can be designed for supercritical steam pressures of 3,500 to 4,500 psia, compared to the steam pressure of 2,400 psia for conventional subcritical boilers. The increase in pressure from subcritical (2,400 psia) to supercritical (3,500 psia) generally improves the net plant heat rate by about 200 Btu/kWh (HHV), assuming the same main and reheat steam temperatures and the same cycle configuration. This increase in efficiency comes at a cost, however, and the economics of the decision between subcritical and supercritical design depend on the cost of fuel, expected capacity factor of the unit, environmental factors, and the cost of capital.

Newly constructed supercritical PC boilers are currently being designed to provide main and reheat steam at 1,050° F or higher. Advancements in metal alloys now allow main steam temperatures of 1,112° F and reheat temperatures of 1,148° F. The US DOE has defined ultra-supercritical steam cycles as operating pressures exceeding 3,600 psia and main superheat steam temperatures approaching 1,100° F[1].

[1] "Materials Development for Ultra-supercritical Boilers", US Department of Energy, Clean Coal Today, Fall 2005

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To date, several ultrasupercritical projects in the US, Europe and Japan have been completed or are soon to be completed. Table 3-1 lists some of the more notable projects that have pushed supercritical PC technology to higher throttle pressures and temperatures.

For this study, FPL is investigating USCPC as a potential candidate for electric power generation capacity at FGPP. Although use of USCPC will be a technology advancement in the US, based on documented success of this technology in Europe and Japan shows that USCPC is not a significant technology risk for FPL.

Beyond what is feasible with current technology, future advancements in the use of high-nickel alloys could allow main steam temperatures to reach 1,292° F with a reheat temperature of 1,328° F; however this technology has not yet been fully developed or tested. The THERMIE 700 project in Europe is the first attempt at these higher steam temperatures. Construction of this plant was originally planned for 2008 with a commercial operation being achieved in 2012; however the progress of this project has appeared to stall. The newer alloyed materials necessary to build a plant of this type would not be commercially available until sometime after the successful operation of the THERMIE 700 or a similar demonstration project. In addition to the boiler improvements that would be necessary to increase steam temperatures, advancements in the steam turbine sector would have to be made in order to reliably sustain higher temperatures. The International Energy Agency's Clean Coal Centre published the history and the possible future of steam temperatures and pressures as shown on Figure 3-1.

Similar to increasing the steam temperature, an increase in steam pressure will also increase efficiency and capital cost. However, the efficiency gain for increased steam pressure is not as great as that for increased temperature. The economics of each situation would have to be examined to optimize the design temperatures and pressure.

With PC technology, coal that is sized to roughly ¾-in. top size is fed to the pulverizers which finely grind the coal to a size of no less than 70 percent (of the coal) through a 200 mesh screen (70 microns). This pulverized coal, suspended in the primary air stream, is conveyed to coal burners. At the burner, this mixture of primary air and coal is further mixed with secondary air and, with the presence of sufficient heat for ignition, the coal burns in suspension with the expectation that combustion will be complete before the burner flame contacts the back wall or sidewalls of the furnace. Current pulverized fuel combustion technology also includes features to minimize unwanted products of combustion. Low NO_x burners or air and fuel staging can be used to reduce NO_x and carefully controlling air-fuel ratios can reduce CO emissions.

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Table 3-1. Notable Worldwide Ultrasupercritical Projects

Power Plant Name (Owner)	Country	MW	Steam Conditions			COD
			Steam Pressure, psia	Main Steam, ° F	Reheat Steam, ° F	
Big Stone 2 (Multiple)	USA	600	3,600	1,080	1,080	2012
Comanche 3 (Xcel)	USA	750	3,800	1,055	1,055	2009
Council Bluffs 4(Mid American)	USA	790	3,690	1,050	1,075	2007
Elm Road 1 & 2 (WE Energies)	USA	2x600	3,800	1,055	1,055	2009
Genesee 3 (EPCOR)	Canada	495	3,626	1058	1054	2005
Holcomb 2 (Sunflower)	USA	700	3,600	1,080	1,080	2011
Holcomb 3 (Sunflower)	USA	700	3,600	1,080	1,080	2012
Holcomb 4 (Sunflower)	USA	700	3,600	1,080	1,080	2013
Iatan 2 (KCP&L)	USA	850	3,686	1,085	1,085	2010
North Rhine-Westphalia Reference Power Plant – 60 Hz	USA	800	4,134	1,112	1,030	2010
Trimble County (LG&E)	USA	750	3,750	1,088	1,088	2010
Red Rock (AEP)	USA	900	4,000	1,100	1,100	2012
Hempstead (AEP)	USA	650	4,000	1,100	1,100	2011
Weston 4 (WPSC)	USA	500	3,800	1,076	1,076	2007
Boa 2 Neurath	Germany	2x1,000	3,771	1,103	1,103	2010
Boxberg 1	Germany	907	3,860	1,013	1,078	2000
Lippendorf	Germany	934	3,873	1,029	1,081	1999
Niederaussem	Germany	1,027	3,989	1,076	1,112	2003
North Rhine-Westphalia Reference Power Plant – 50 Hz	Germany	600	4,134	1,112	1,148	2008
Hemweg 8	Netherlands	680	3,844	1,004	1,054	1994
Avedoere 2	Denmark	450	4,351	1,076	1,112	2002
Nordjylland 3	Denmark	411	4,206	1,080	1,076	1998
Isogo 1	Japan	600	4,061	1,121	1,135	2002
Hitachi Naka, Tokyo Electric Power	Japan	1,000	3,675	1,112	1,112	2003

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Table 3-1. Notable Worldwide Ultrasupercritical Projects

Power Plant Name (Owner)	Country	MW	Steam Conditions			COD
			Steam Pressure, psia	Main Steam, ° F	Reheat Steam, ° F	
Hranomachi 2, Tohoku Electric Power	Japan	1,000	3,675	1,112	1,112	1998
Tachibanawan 1	Japan	1,050	3,750	1,121	1,135	2000
Changshu	China	3x600	3,684	1,009	1,060	2006
Chugoku EPCO Misumi 1	China	1,000	3,556	1,112	1,112	1998
Huaneng	China	4 x 1,000	3,844	1,112	1,112	2008
Waigaoqiao	China	2 x 900	4,047	1,008	1,044	2004
Wangqu	China	2 x 600	3,989	1,060	1,056	2007
Zouxian IV	China	2 x 1,000	3,916	1,112	1,112	2008

COD--Commercial Operation Date

Note:

Data reported from various sources, not all data can be verified.

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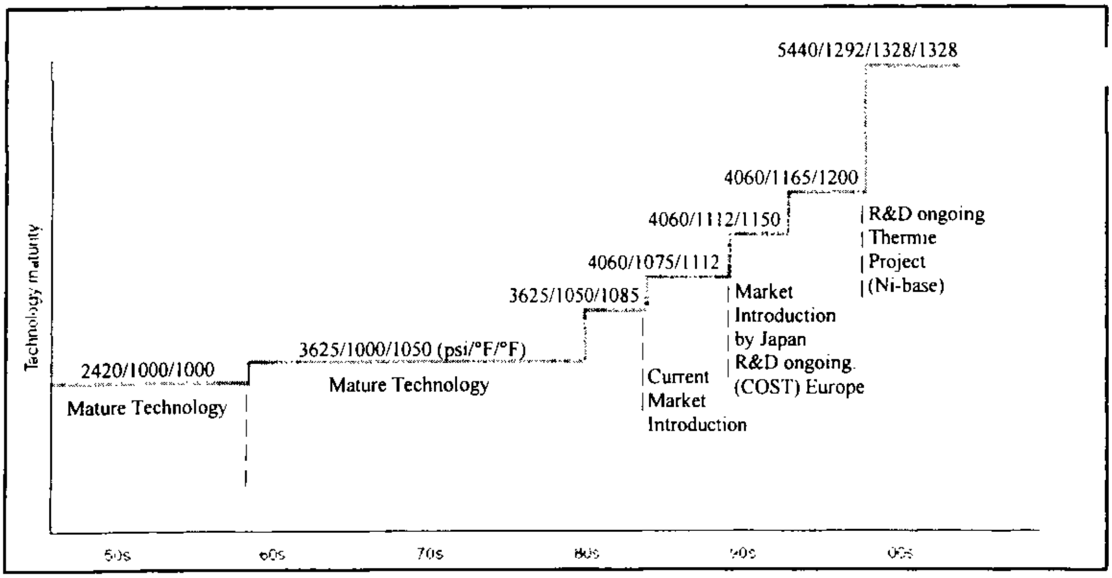

Figure 3-1. Trends in Steam Conditions of Coal-Fired Power Plants[1]

Because of the high combustion temperature of PC at the burners, the furnace enclosure is constructed of membrane waterwalls to absorb the radiant heat of combustion. This heat absorption in the furnace is used to evaporate the preheated boiler feedwater that is circulated through the membrane furnace walls. The steam from the evaporated feedwater is separated from the liquid feedwater and routed to additional heat transfer surfaces in the steam generator. Once the products of coal combustion (ash and flue gas) have been cooled sufficiently by the waterwall surfaces so that the ash is no longer molten but in solid form, heat transfer surfaces, predominantly of the convective type, absorb the remaining heat of combustion. These convective heat transfer surfaces include the superheaters, reheaters, and economizers located within the steam generator enclosure downstream of the furnace. The final section of boiler heat recovery is in the air preheater, where the flue gas leaving the economizer surface is further cooled by regenerative or recuperative heat transfer to the incoming combustion air.

Though the steam generating surfaces are designed to preclude the deposition of molten or sticky ash products, on-line cleaning systems are provided to enable removal of ash deposits as they occur. These on-line cleaners are typically soot blowers that utilize either high-pressure steam or air to dislodge ash deposits from heat transfer surfaces or,

[1] "Profiles", IEA Clean Coal Centre, November 2002. Available at:
http://www.iea-coal.org.uk/publishor/system/component_view.asp?PhyDocId=5385&LogDocId=81049

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in cases with extreme ash deposition, utilize high-pressure water cannons to remove molten ash deposits from evaporative steam generator surfaces. The characteristics of the coal, such as ash content and ash chemical composition, dictate the type, quantity, and frequency of use of these on-line ash cleaning systems. Ash characteristics also dictate steam generator design regarding the maximum flue gas temperatures that can be tolerated entering convective heat transfer surfaces. The design must ensure that ash in the flue gas stream has been sufficiently cooled so it will not rapidly agglomerate or bond to convective heat transfer surfaces. In the case of very hard and erosive ash components, the flue gas velocities must be sufficiently slow so that the ash will not rapidly erode heat transfer surfaces.

With PC combustion technology, the majority of the solid ash components in the coal will be carried in the flue gas stream all the way through the furnace and convective heat transfer components to enable collection with particulate removal equipment downstream of the air preheaters. Typically, no less than 80 percent of the total ash will be carried out of the steam generator for collection downstream. Roughly 15 percent of the total fuel ash is collected wet from the furnace as bottom ash, and 5 percent is collected dry in hoppers located below the steam generator economizer and regenerative air heaters.

3.2 PC Vendors

There are currently eight major manufacturers of PC steam generators. These manufacturers are listed in Table 3-2.

Table 3-2. PC Boiler Vendors

• Alstom	• Foster Wheeler (FW)
• Babcock Power (BP)	• Ishikawajima Harima Heavy Industries (IHI)
• Babcock & Wilcox (B&W)	• Mitsubishi Heavy Industries (MHI)
• Babcock-Hitachi (B-H)	• Mitsui Babcock (MB)

The current utility steam generator technology offered by the major vendors is similar, with the exception of boiler tube construction, commercially available alloys, and burner arrangement and technology.

3.2.1 Boiler Tube Construction

All subcritical boilers use vertical tubes; nearly all of the vendors use smooth tubes except Babcock & Wilcox which uses a slightly rifled tube. There are two main

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design philosophies for supercritical boiler tube design. Either a vertical rifled or spiral wound tube is used. The two designs are shown on Figure 3-2.

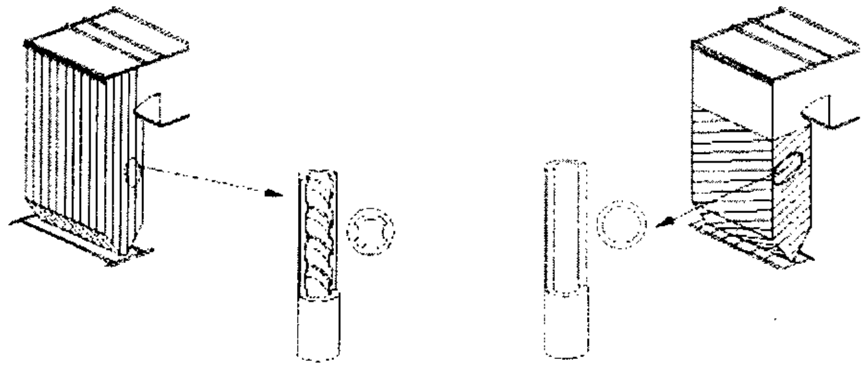

Figure 3-2. Vertical Rifled and Smooth Spiral Wound Tube Design (MHI).

There are numerous advantages and disadvantages to both the vertical and spiral tube designs. The vertical tube from a design standpoint is considered to be more ideal, however in practice the spiral tube design is the accepted technology. By nature in a rectangular boiler different sections of the furnace wall will see different temperatures. This can cause problems in a vertical tube arrangement where the feedwater cannot travel vertically. Certain sections of the wall will receive excess heating which can cause failure while others will be exposed to less heat. In a spiral wound design where the tube wraps around the furnace wall each tube will be exposed to the same amount of heat and this problem is avoided.

Thus current boiler designs implement the spiral tube design in the lower furnace and then switch to the vertical tube design in the upper furnace where the heat flux is lower. The disadvantage of the spiral tube design is that there is a much larger pressure drop through the tube compared to the vertical tube design. This pressure drop increases the work the feedwater pump must perform, thus lowering the overall efficiency of the plant. The capital costs associated with a vertical tube furnace are also lower, because the design requires a much simpler construction with less supporting structures. Because of the savings that could be experienced by using a vertical tube design, work is being performed to try and overcome the challenges faced by the vertical tube design.

The most prominent challenge of implementing a vertical tube design is its inability to handle the high heat flux in the lower furnace. As shown on Figure 3-2, one of the recent developments to aid with this issue is to use ribs within the tube instead of a smooth wall. This increases heat transfer area and creates turbulence within the tube, which increases overall heat transfer rates to the water and keeps the tubes cooler.

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A possible advantage of a vertical tube design is its ability to operate in natural circulation. Current supercritical boiler tube designs rely on forced circulation systems. New vertical tube designs are currently being developed to operate in natural circulation. A characteristic of natural circulation subcritical boilers is that when the water within the tube heats up the mass flow rate will also increase, thus drawing in more cooler water to maintain a safe tube temperature. In a supercritical application this characteristic would automatically control problems associated with boiler tubes overheating. However this characteristic has only been shown to occur in laboratory tests and there is no actual experience with a supercritical power plant using this technology.

Table 3-3 highlights the advantages and disadvantages of vertical rifled tubes versus spiral wound tubes.

Table 3-3. Vertical Rifled Tubes vs. Spiral Wound Tubes

Vertical Rifled Tubes	Spiral Wound Tubes
Lower Capital Costs • Simpler Construction • Self Supporting Tubes	Higher Capital Costs • More Complex Construction
Lower Operating Costs • Lower Pressure Drop • Less Feedwater Pumping Required	Higher Operating Costs • Higher Pressure Drop • More Feedwater Pumping Required
Can Operate in Natural Circulation	Forced Circulation Operation Only
Less Operating History	Proven Technology

3.2.2 Commercially Available Alloys

In addition to the type of boiler tube, selecting the tube material is a major design decision. There are currently a number of steel alloys available for use in boiler tube construction. Table 3-4 displays some of the more common alloying elements and the properties they exhibit. While Table 3-4 describes the general characteristics of alloying elements, metallurgy is a complicated science, and small variations in the combination of elements at different heating temperatures can produce varying results.

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Table 3-4. Common Alloying Elements

Alloying Element	Properties
Chromium	Increases high temperature strength, adds resistance to corrosion and oxidation
Nickel	Increases hardenability and impact strength
Chromium – Nickel	Tends to add the positive properties of each element without the negative aspects
Molybdenum	Increases hardenability and creep strength
Vanadium	Increases yield and tensile strength

The common steel alloys are primarily differentiated by their cost, strength, and temperature properties. Capital costs associated with the alloy increase with increased temperature resistance and increased strength. Using an alloy that can withstand higher temperatures allows for higher steam temperatures. Higher steam temperatures directly correlate to increased boiler efficiencies. The higher capital cost of the alloy can be offset by this increase in boiler efficiency. Table 3-5 lists some of the common alloys and their associated pressure/temperature operating limits for boiler applications.

Another benefit is the increased strength properties of the alloyed steels. By using a stronger alloy, a smaller pipe diameter and thickness can be used. This results in significant weight savings in the boiler. A lighter boiler requires less structural support and this lowers the material cost during construction of pipe supports, structural steel, and equipment connection loads. Smaller component thickness allows for more operating flexibility as well. A plant with large thick sections will be limited to the ramp rates it can safely achieve. Replacing thick sections with thin sections allows for quicker heat transfer from inside the furnace to the feedwater or steam, this allows for larger ramp rates and better load matching capability.

The following is a discussion of the current commercially available alloys and their respective applications.

3.2.2.1 Boiler Tubes

P22, P91, and P92 are some of the most commonly used steel alloys. These steels are primarily alloyed with chromium (P22 - 2.25 percent chromium, P91 and P92 – 9 percent chromium) and also contain smaller amounts of molybdenum. P91 is now used in favor of P22, because of the higher temperatures and pressures it can handle. P92 is similar to P91, but it contains up to 2 percent tungsten in addition the chromium and molybdenum present in P91. P92 is used in installations where it will be exposed to temperatures higher than what P91 can withstand.

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Table 3-5. Coal-Fired Power Generation Boiler Temperature and Material Development

Live Steam		Application Date	Alloy	Equivalent Material
Pressure, psi	Temperature, ° F			
<2,900	<968	Since the early 1960s	X20	Cr Mo V 11 1
<3,626	<1,004	Since the early 1980s	P22	2 ¼ Cr Mo
<4,351	<1,040	Since the late 1980s	P91	9Cr - 1Mo
<4,786	<1,148	Since 2004	P92	X10CrWMoVNb9-1, Europe STBA29-STPA29, Japan
<5,076	<1,292	Expected in 2010	Super Alloys	CCA 617 - IN 740 Haynes 230 - Save 12

Source: M.R. Susta and K. George, "Ultra-Supercritical Pulverized Coal Fired Power Plants," CoalGen 2006, Cincinnati, OH, August 16-18, 2006

3.2.2.2 Superheater Tubes

Superheater tubes have been previously constructed out of materials such as T20 or X20, but due to poor corrosion resistance austenitic steels are now more commonly used. Suitable materials for applications up to 1,050° F are the austenitic steels T316 and T346[1]. NF709 and HRC3 are considered suitable for applications of up to 1,112° F main steam temperature.

[1] "Supercritical Steam Cycles for Power Generation Applications," Department of Trade and Industry, January 1999.

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3.2.2.3 Headers, Manifolds, Piping

For lower steam temperatures of 1,050° F carbon steel X20CrMoV121 can be used. To achieve higher steam temperatures P91/T91/F91 should be used[1]. For 1,112° F main steam temperature applications ferritic steels P92, P122 and the austenitic steel X3CrNiMoM1713 are considered to be the suitable commercially available options.

In the future advancements in nickel alloys could allow for main steam temperatures of 1,292° F.

Figure 3-3 is a chart presented by Alstom, a major boiler manufacturer, showing their recommended boiler alloys for particular steam conditions. Alstom has included a timeline showing expected availabilities of nickel alloy materials.

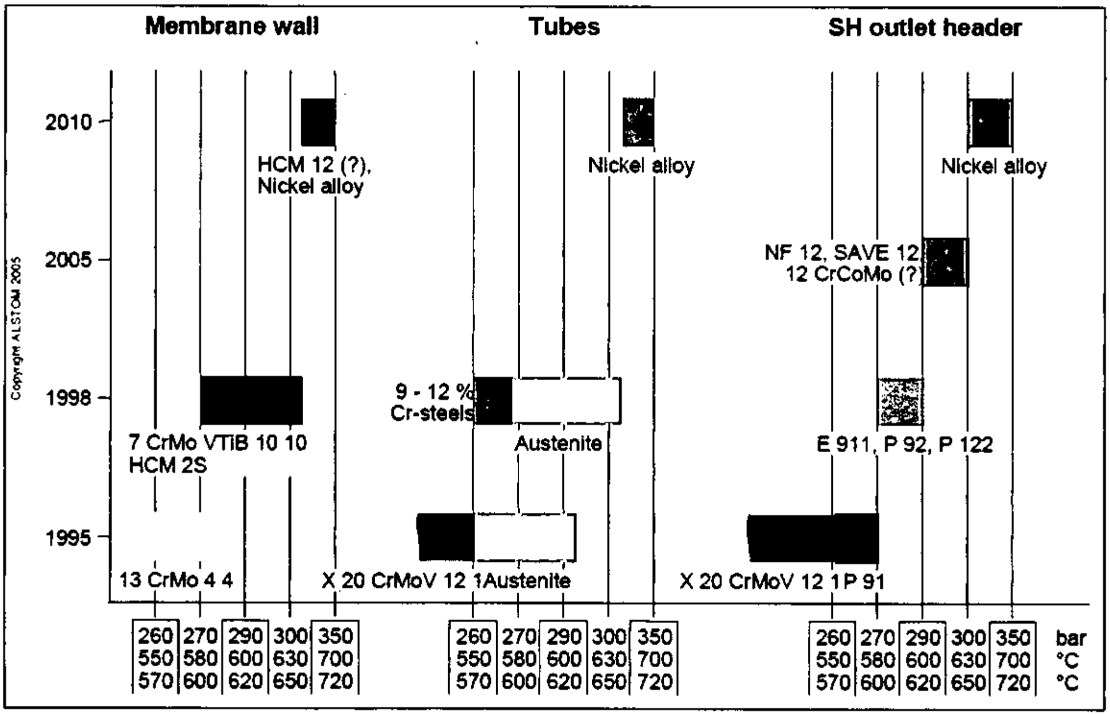

Figure 3-3. Alstom Boiler Alloys and Steam Conditions

Determining which alloy to use depends on the particular application. In some cases the increased capital cost can be offset by increased boiler efficiency, lower emissions, and lower structural cost. The most common practice for alloy selection is to first determine the surface temperature of the boiler tubes from the boiler design and then select an alloy that can withstand that temperature.

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3.2.3 Burner Arrangement

PC boiler burners can be arranged in either a wall-fired or a corner or tangentially fired set-up. The wall-fired burners are either rear or front wall firing or they can be set up as front and rear-wall opposed. Corner or tangential fired set-ups typically have the burners firing from each of the four corners of the furnace.

3.3 Fluidized Bed

During the 1980s, fluidized bed combustion (FBC) rapidly emerged as a viable alternative to PC-fueled units for the combustion of solid fuels. Initially used in the chemical and process industries, FBC was applied to the electric utility industry because of its perceived advantages over competing combustion technologies. SO_2 emissions could be controlled from FBC units without the use of external scrubbers, and NO_x emissions from FBC units are inherently low. Furthermore, FBC units are "fuel flexible," with the capability to fire a wide range of solid fuels with varying heating values, ash contents, and moisture contents. Additionally, slagging and fouling tendencies were minimized in FBC units because of the low combustion temperatures.

There are several types of fluidized bed technologies, as illustrated on Figure 3-4. Pressurized FBC is currently a demonstration technology and will not be discussed here. Atmospheric FBC (AFBC) is generally divided into two categories: bubbling and circulating. A typical AFBC is composed of fuel and bed material contained within a refractory-lined, heat absorbing vessel. The composition of the bed during full-load operation is typically in the range of 98 percent bed material and only 2 percent fuel. The bed becomes fluidized when air or other gas flows upward at a velocity sufficient to expand the bed. At low fluidizing velocities (3 to 10 ft/sec), relatively high solid densities are maintained in the bed and only a small fraction of the solids are entrained from the bed. A fluid bed that is operated in this velocity range is referred to as a bubbling fluidized bed (BFB).

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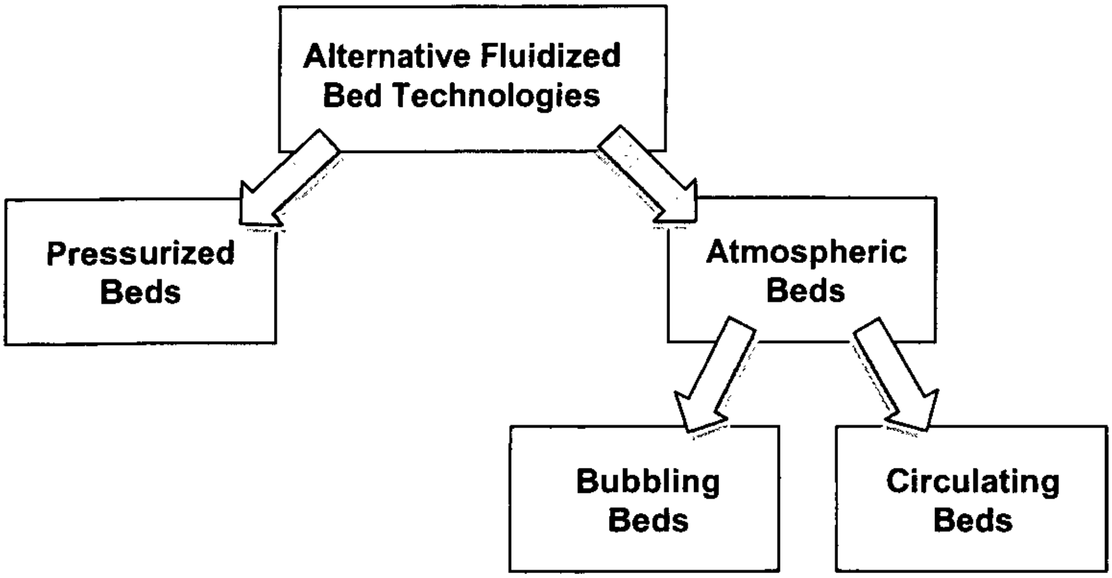

Figure 3-4. Fluidized Bed Technologies

If the fluidizing velocity is increased, smaller particles are entrained in the gas stream and transported out of the bed. The bed surface, well defined for a BFB combustor, becomes more diffuse; solids densities are reduced in the bed. A fluid bed that is operated at velocities in the range of 13 to 22 ft/sec is referred to as a circulating fluidized bed, or CFB. The CFB has better environmental characteristics and higher efficiency than BFB and is generally the AFBC technology of choice for fossil fuel applications greater than 50 MW.

The primary coal fired boiler alternative to a PC boiler is a CFB boiler. In a CFB unit, a portion of the combustion air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone (for sulfur capture), and ash. The bottom of the bed is supported by water-cooled membrane walls with specially designed air nozzles that uniformly distribute the air. The fuel and limestone are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. Staged combustion and the low combustion temperature limit the formation of thermal NO_x.

The bed fluidizing air velocity is greater than the terminal velocity of most of the particles in the bed and, thus, fluidizing air carries the particles through the combustion chamber to the particulate separators at the furnace exit. The captured solids, including any unburned carbon and unused calcium oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. This internal

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solids circulation provides longer residence time for the fuel and limestone, resulting in good combustion and improved sulfur capture.

Commercial CFB units offer greater fuel diversity than PC units, operate at competitive efficiencies, and, when coupled with a polishing SO_2 scrubber, operate with emissions below the current levels mandated by federal standards. Compared to conventional PC technology, which was first utilized in the 1920s, CFB is a commercially proven technology that has been in reliable electric utility service in the United States for only the past 20 years.

By the late 1980s, the transition had been made from small industrial-sized CFB boilers to several operating electrical utility reheat boilers, ranging in size from 75 to 165 MW. Several reheat boilers of over 300 MW are currently in service, and boiler suppliers are offering boiler designs to provide steam generation sufficient to support up to 600 MW, but none has been built larger than 340 MW. Fuels for these applications range from petcoke and bituminous coal to high ash refuse from bituminous coal preparation and cleaning plants, and high moisture fuels such as lignite.

An environmentally attractive feature of CFB is that SO_2 can be removed during the combustion process by adding limestone to the fluid bed. The CaO formed from the calcination of limestone reacts with SO_2 to form calcium sulfate, which is removed from the flue gas with a conventional particulate removal device. The CFB combustion temperature is controlled at approximately 1,600° F, compared to approximately 2,500 to 3,000° F for conventional PC boilers. Combustion at the lower temperature has several benefits. First, the lower temperature minimizes the sorbent (typically limestone) requirement, because the required calcium to sulfur (Ca/S) molar ratio for a given SO_2 removal efficiency is minimized in this temperature range. Second, 1,550 to 1,600° F is well below the ash fusion temperatures of most fuels, so the fuel ash never reaches its softening or melting points. The slagging and fouling problems that are characteristic of PC units are significantly reduced, if not eliminated. Finally, the lower temperature reduces NO_x emissions by nearly eliminating thermal NO_x. Figure 3-5 illustrates the benefits of the lower combustion temperature for CFBs.

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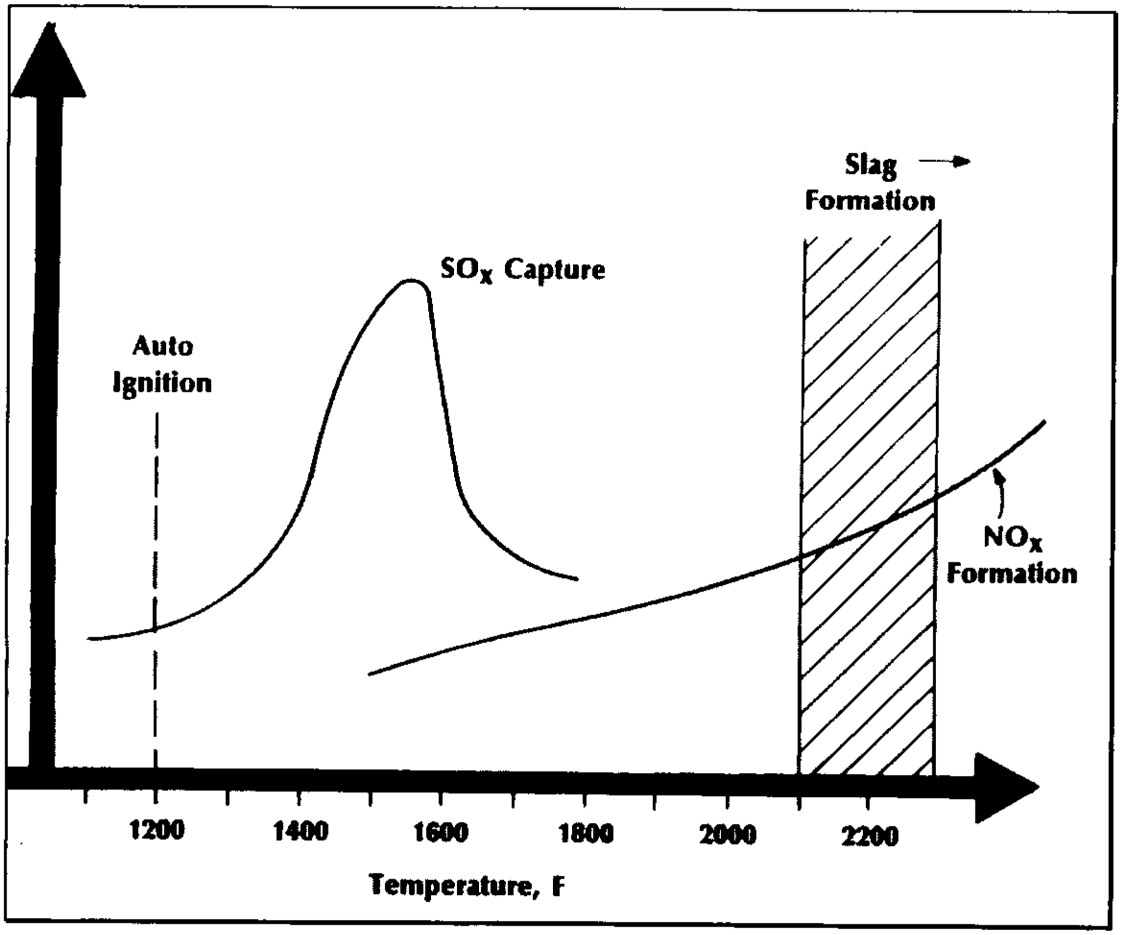

Figure 3-5. Environmental Benefits of CFB Technology

Since combustion temperatures are below ash fusion temperatures, the design of a CFB boiler is not as dependent on ash properties as is a conventional PC boiler. With proper design considerations, a CFB boiler can fire a wider range of fuels with less operating difficulty.

A typical CFB arrangement is illustrated schematically on Figure 3-6. In a CFB, primary air is introduced into the lower portion of the combustion chamber, where the heavy bed material is fluidized and retained. The upper portion of the combustor contains the less dense material that is entrained with the flue gas from the bed. Typically, secondary air is introduced at higher levels in the combustor to ensure complete combustion and to reduce NO_x emissions. The combustion gas generated in the combustor flows upward, with a considerable portion of the solids inventory entrained. These entrained solids are separated from the combustion gas in hot cyclone-type dust collectors or in mechanical particulate separators and are continuously returned to the combustion chamber by a recycle loop. The cyclone separator and recycle loop may

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include additional heat recovery surface to control the bed temperature and steam temperature and to minimize refractory requirements.

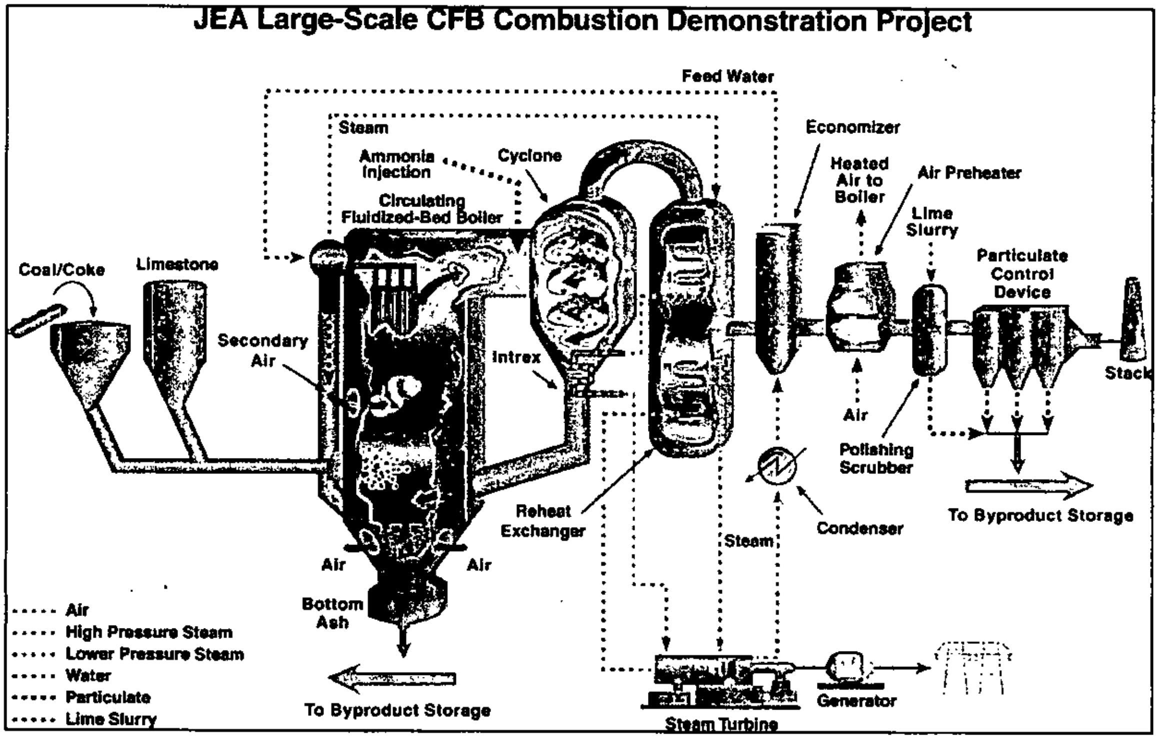

Figure 3-6. Typical CFB Unit

The combustion chamber of a CFB unit generally consists of membrane-type welded waterwalls that provide most of the evaporative boiler surface. Heat transfer to evaporative surfaces is primarily through convection and conduction from the bed material that contacts the evaporative wall surfaces or division panel surfaces located in the upper combustor. The lower third of the combustor is refractory lined to protect the waterwalls from erosion in the high-velocity dense bed region.

The fuel size for a CFB boiler is much coarser than the pulverized fuel needed for suspension firing in a PC boiler. Compared to the typical 70 micron particle size for a PC unit, the typical fuel size for a CFB is approximately 5,000 microns. Especially for high ash fuels, the use of larger fuel sizing reduces auxiliary power and pulverizer maintenance requirements and eliminates the high cost of pulverizer installation.

Ash removal from the CFB boiler is from the bottom of the combustor and also from fly ash that is entrained in the flue gas stream, similar to PC boilers. With a CFB boiler, the ash split between bottom ash and fly ash is roughly 50 percent bed ash and 50 percent fly ash. All of the ash drains from CFB boilers are typically retained in a dry

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condition without the need for water impounded hoppers or water submerged conveyors, typically utilized for PC boiler bottom ash collection and conveying.

3.4 Technical Characteristics of PC Versus CFB

The technical characteristics of the two competing boiler technologies were addressed in the previous section. Table 3-6 compares PC and CFB across several different parameters; these are summarized in the following subsections.

3.4.1 Environmental

Environmental impacts are categorized as flue gas emissions, solid waste production, and water consumption:

- **Flue Gas Emissions**--In the US, PC and CFB technologies will be required to meet similar emissions levels.
- **Solid Waste Production**--Solid waste production for the two technologies would be similar, except that the bottom ash from the PC boiler would be transported in a wetted condition because of the bottom ash collection technology, which includes either water impounded bottom ash hoppers or submerged conveyors below the furnace bottom. Bed ash extraction from a CFB is a dry process, where the ash is collected in a granular form and cooled with a combination of fluidizing cooling air and water jacketed screw coolers. The quantity of sorbent required for sulfur removal will affect the relative volume of solid waste.
- **Water Consumption**--Water consumption for the two technologies would be essentially identical for the boiler drum blowdown to maintain boiler water quality; however, when steam is used for soot blowing, the boiler water makeup requirements may be slightly higher because of the higher soot blowing steam demand of PC boiler technology.

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Table 3-6. PC Versus CFB Boiler Comparison

Evaluation Parameter	PC Boiler	CFB Boiler
Environmental		
NO_x	SCR	SNCR
SO_2	FGD	Limestone injection and polishing FGD
Particulate	Fabric filter	Fabric filter
Operational		
Auxiliary Power	Base	Slightly higher
Maintenance	Base	Slightly higher
Fuel Flexibility	Within design coals	Better
Startup and Load Ramping	Base, 5 percent per minute	4 hours additional startup time, 2 to 3 percent per minute
Availability and Reliability	Base	Same
Technology Maturity	Well established	Recently constructed in 300 MW size
Capital Costs	Base	Slightly higher
Fixed O&M Costs	Base	Slightly higher
Variable O&M (Nonfuel) Costs	Base	Typically, slightly higher
Net Plant Heat Rate	Base	Higher

SCR--Selective Catalytic Reduction

FGD--Flue Gas Desulfurization

SNCR--Selective Non-catalytic Reduction

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3.4.2 Operational

Operational impacts are categorized as auxiliary power, maintenance, fuel flexibility, startup, and load ramping:

- **Auxiliary Power**--The power requirements of the primary air fans for the CFB boiler provide the motive power to fluidize and circulate the bed material. This is a higher power requirement than that of the primary air fans for a PC boiler application. Since CFB boilers do not need pulverizers, the power savings from this normally results in the auxiliary power requirements for the two boiler technologies being relatively similar, with CFB requirements being slightly higher.
- **Maintenance**--The major maintenance requirements of CFB boilers involve the refractory repairs caused by the erosive effects of the bed materials circulating through the boiler components. Initial CFB boiler applications experienced significant refractory maintenance requirements. Subsequent refractory system improvements, materials, and installation techniques have provided significant reductions in these maintenance requirements. The major maintenance requirements of PC boilers and their auxiliaries are often associated with pulverizers, soot blowers, and associated heat transfer surface damage caused by soot blower erosion in areas where excessive soot blowing is needed to prevent the accumulation of agglomerating ash deposits. Unlike PC boilers, CFB boilers do not require pulverizers. In addition, CFB boilers require fewer soot blowers because the coal ash temperature is not elevated to the point where it becomes molten or agglomerating. The O&M cost of PC is slightly less than that of CFB.
- **Fuel Flexibility**--CFB boilers have the capability of superior fuel flexibility compared to PC boilers. Since the combustion temperature of CFB boilers is below the ash initial deformation temperature, the slagging and fouling characteristics of alternative fuels are not of concern. As long as the CFB boiler auxiliaries, such as fuel feed equipment and ash removal equipment, are provided with sufficient capacity, a wide range of fuel heating values and ash content can be utilized. The capacity of the sorbent feed equipment also needs to be designed for the range of fuel sulfur content that is expected to occur. Because of the long fuel residence time in the CFB boiler combustion loop, a very wide range of fuel volatile matter content can also be utilized. A CFB boiler can efficiently burn fuels in ranges of volatility well below those required in a PC boiler.

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- **Startup**--Because of the large mass of bed material and larger quantity of refractory in a CFB boiler compared to a PC boiler, CFB boilers are somewhat less suited for numerous startups and cycling service than are PC boilers. The large mass of bed material results in significantly higher thermal inertia for a CFB boiler compared to a PC boiler. Startup from cold conditions can be extended for several hours. This higher thermal inertia can also result in unstable bed performance during periods of rapid load changes. Optimal sorbent feed for FGD is achieved during baseload operation, which enables consistent bed inventory, desulfurization, and sorbent utilization. CFB boilers have some advantages during hot and warm restarts, because the refractory and bed hold a significant amount of heat.
- **Load Ramping**--CFB boilers are generally capable of ramp rates of 2 to 3 percent per minute, but may be restricted to 1 to 2 percent per minute to control steam conditions, SO_2 emissions, and limestone stoichiometry fluctuations. PC boilers are generally capable of ramp rates of 5 percent per minute.

3.4.3 Availability and Reliability

Over the past 20 years that CFB boilers have been utilized for steam production for electric power generation, the availability and reliability have improved and are considered to be generally equivalent to PC boilers. Several improvements in refractory system designs, fuel and sorbent feed system designs, and ash extraction equipment design have been made that adequately address the initial problems encountered with these system components. These systems are high maintenance and can cause lower overall availability of CFB compared to PC. Since CFB boiler systems do not have pulverizers, do not have multiple burner systems with a large number of moving or controlled components, and have significantly fewer soot blowers, many of the high maintenance components of PC boilers are avoided.

3.4.4 Technology Maturity

Though CFB boilers have been used to provide steam for reheat turbine electric power generation for more than 20 years, the steaming capacities have been limited to less than 150 MW in most cases. In recent years, manufacturers have increased unit size to the point where there are more reheat boilers in service supporting electrical generation up to 300 MW gross output, with the largest being 320 MW net. These units are currently in service or under construction and are designed to burn the full range of solid fuels including low volatile anthracite, petcoke, subbituminous coal, high volatile

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bituminous coal, and high moisture lignite. CFB boiler manufacturers are currently proposing to supply units with capacities in excess of 400 MW electrical output. PC boilers have been installed and are operating with steaming capacities sufficient to support up to 1,300 MW of electrical generation. Because of the economies of scale for PC boiler and their auxiliaries, recent PC boiler installations have been predominantly larger than 250 MW. Many of the newer units have been designed to operate with supercritical steam pressure conditions.

3.5 FBC Experience in the United States

The first utility-grade AFBC unit was constructed in Rivesville, West Virginia, in 1976, a 30 MW (electric) Foster Wheeler BFB unit. One of the first utility-grade CFB units was the Tri-State Nucla project, completed in 1987. This 110 MW unit from Foster Wheeler was a Department of Energy (DOE) Clean Coal Demonstration Project. In the late 1980s and early to mid-1990s, a significant number of CFB units came online. In the early 1990s, the industry began to view CFB as a mature technology. The initial US CFB units were predominantly fired on bituminous coals. Around 1995, the trend reversed and almost all CFB units since that time have fired waste coals, lignites, or opportunity fuels such as petcoke and biomass. The field of international CFB vendors has consolidated to four dominating players: Alstom, Foster Wheeler, Lurgi, and Kvaerner Pulping. Alstom and Foster Wheeler have dominated the US and international markets for units above 150 MW. Lurgi does not actively market in the US.

CFB units have been increasing in size over the last 15 years, with the largest US operating CFB units at 300 MW (JEA Northside). The largest unit in operation is the ENEL Sulcis Unit in Sardinia, Italy. This Alstom unit is the equivalent of 340 MW, comprised of a 220 MW repowering unit along with additional process steam requirements.

Alstom, Foster Wheeler, and Lurgi have developed designs for single units in the 500 to 600 MW range. Alstom and Foster Wheeler have 600 MW designs, while Lurgi's largest design is 500 MW.

3.6 Current PC and CFB Project Development

There are numerous PC and CFB project currently being developed in the United States. Most of these will employ subcritical and supercritical steam conditions. These projects have been identified by the National Energy Technology Laboratory and are also

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tracked by Black & Veatch as the projects currently in development that may to move forward to construction.[1] These projects are listed in Table 3-7.

Table 3-7. Currently Announced PC and CFB Project Developments.

Project/Company	Size (MW)	Fuel	Technology	Location	Expected COD
MDU / Hardin	116	PRB	Subcritical	MT	2006
Manitowoc / Unit 9	63	Unknown	CFB	WI	2006
Tri-State / Springerville 3	418	PRB	Subcritical	AZ	2006
Santee Cooper / Cross Unit 3	600	Cent. App	Subcritical	SC	2007
XCEL / King	600	PRB	Supercritical	MN	2007
MidAmerican / CB4	790	PRB	Supercritical	IA	2007
Newmont / TS Ranch Plant	203	PRB	Subcritical	NV	2008
Black Hills / Wyg2 Unit 4	90	PRB	Subcritical	WY	2008
WPSC / Weston 4	530	PRB	Supercritical	WI	2008
TXU / Sandow	564	Lignite	CFB	TX	2009
TXU / Oakgrove U1	800	Lignite	Supercritical	TX	2009
TXU / Oakgrove U2	800	Lignite	Supercritical	TX	2009
CWLP / Dallman 34	201	Illinois	Subcritical	IL	2009
EKPC / Spurlock 4	278	Bituminous	CFB	KY	2009
CLECO / Rodemacher	600	Petcoke	CFB	LA	2009
Santee Cooper / Cross Unit 4	600	Cent.App.	Subcritical	SC	2009
WE Energies / Elm Road 1	615	Illinois	Supercritical	WI	2009
OPPD / Nebraska City 2	663	PRB	Subcritical	NE	2009
Salt River / Springerville 4	400	PRB	Subcritical	AZ	2010
NRG / Big Cajn. II, 4	675	PRB	Supercritical	LA	2010
CUS / Southwest U2	300	PRB	Subcritical	MO	2010
KCP&L / Iatan Unit 2	850	PRB	Supercritical	MO	2010
TXU / Texas Sites	8 x 800	PRB	Supercritical	TX	2010
NAPG / Two Elk	325	PRB	Subcritical	WY	2010

[1] "Tracking New Coal-fired Power Plants," NETL, S. Klara, E Shuster, September 29, 2006

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Table 3-7. Currently Announced PC and CFB Project Developments.

Project/Company	Size (MW)	Fuel	Technology	Location	Expected COD
LG&E / Trimble Cty 2	732	Illinois Basin	Supercritical	KY	2010
LSP / Plum Point 1	665	PRB	Supercritical	AR	2010
CPS / Spruce 2	758	PRB	Subcritical	TX	2010
WE Energies / Elm Road 2	615	Illinois	Supercritical	WI	2010
XCEL / Comanche 3	750	PRB	Supercritical	CO	2010
Sierra Pacific / Ely Energy Ctr	750	Unknown	Supercritical	NV	2011
Sithe / Desert Rock 1	750	Unknown	Supercritical	NV	2011
LSP / White Pine	2 x 800	PRB	Supercritical	NV	2011
LSP / Elk Run	750	PRB	Supercritical	IA	2011
Peabody CMS / Prairie Stste 1	750	Illinois	Supercritical	IL	2011
Sunflower / Holcomb 2	600	PRB	Supercritical	KS	2011
LSP / Sandy Creek,	800	PRB	Subcritical	TX	2011
WF&Brazos / Hugo 2	750	PRB	Supercritical	OK	2011
Duke / Cliffside Unit 5	800	Bituminous	Supercritical	NC	2011
EKPC / J.K. Smith 1	278	Bituminous	CFB	KY	2011
S Mont.-SME / Highwood	250	Montana	CFB	MT	2011
Basin Elec. / Dry Fork-	385	PRB	Subcritical	WY	2011
AEP / Hempstead	650	PRB	Ultra-Supercritical	AR	2011
AECI / Norborne 1	660	PRB	Supercritical	MO	2011
Big Stone II Owners / Big Stone II	600	PRB	Supercritical	SD	2012
Santee Cooper / Great Pee Dee River 1	600	East KY Bituminous	Supercritical	SC	2012
NRG / Limestone U3	800	PRB	Supercritical	TX	2012
Sithe / Desert Rock 2	750	Unknown	Supercritical	NV	2012
Sithe / Toquop	750	Unknown	Supercritical	NV	2012
Alliant-WP&L	300	PRB & Bit	CFB	WI	2012
AMP Ohio	500	Bituminous & PRB	Unknown	OH	2012
FPL / FGPP Unit 1	1000	Bituminous	Ultra-Supercritical	FL	2012
UAMPs/Pacificorp / IPP 3	900	UT/CO	Unknown	UT	2012
AEP / Red Rock	900	PRB	Ultra-Supercritical	OK	2012
Sunflower / Holcomb 3	700	PRB	Supercritical	KS	2012
LSP / Longleaf	2 x 600	PRB/Bit.	Unknown	GA	2012

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Table 3-7. Currently Announced PC and CFB Project Developments.

Project/Company	Size (MW)	Fuel	Technology	Location	Expected COD
Peabody-CMS / Prairie Stats 2	750	Illinois	Supercritical	IL	2012
Dominion / Wise Co. VA	600	Bit, Waste Coal/Bio	CFB	VA	2012
BPU / Nearman Cr 2	235	PRB	Subcritical	MO	2012
Duke / Cliffside 7	800	Bituminous	Supercritical	NC	2012
Seminole / Palatka 3	750	Bituminous /Illinois 6 /Petcoke	Supercritical	FL	2012
PPGA / Hastings 2	220	PRB	Subcritical	NE	2012
PacificCorp / Hunter Unit 4	400	Unknown	Supercritical	UT	2013
Santee Cooper / Great Pee Dee River U2	600	East KY Bituminous	Supercritical	SC	2013
Alliant-IP&L	600	PRB	Supercritical	IA	2013
AMP Ohio	500	Ohio & PRB	Unknown	OH	2013
Sunflower / Holcomb 4	600	PRB	Supercritical	KS	2013
JEA/FMPA / Taylor	800	Bituminous	Supercritical	FL	2013
PacificCorp / J. Bridger 4	750	PRB	Supercritical	WY	2014
FPL / FGPP Unit 2	1000	Bituminous	Ultra-Supercritical	FL	2013
Sierra Pacific / Ely Energy Ctr 2	750	Unknown	Supercritical	NV	2014
Tri-State / CO Coal Unit	656	PRB	Supercritical	KS	2020

Note:
This list is a compilation of known projects as published by NETL and Black & Veatch, independently. Not all data can be verified.

3.7 Post Combustion Carbon Capture

For PC and CFB technologies, the likely approach for CO_2 capture would be a post-combustion CO_2 capture process. In CO_2 capture, the CO_2 concentration and the CO_2 partial pressure in the gas stream are important variables. Higher concentrations and higher partial pressures of CO_2 facilitate its capture. The relatively low concentration of CO_2 in the flue gas makes the CO_2 capture process difficult.

Because the carbon capture technology is implemented as "post-combustion" for PC and CFB technologies, the steam generation equipment is constructed and operated the same as it would be for a plant without carbon capture. The resulting flue gas would be treated by removing the CO_2, which would then be dehydrated, compressed, and transported.

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The addition of a carbon capture process would have a significant impact on the output and heat rate of a PC or CFB facility. Significantly higher auxiliary loads are required for additional pumps, fans, and miscellaneous loads in the capture process, and thermal energy in the form of process steam is required to separate the CO_2 from the absorption solvent. Energy would also be required for captured CO_2 compression. These energy requirements would have an impact on the net plant output and net plant heat rate of the facility. In order to maintain project required net plant output, additional generation capacity would need to be installed to compensate for the increased auxiliary loads of the carbon capture process. The increase in gross plant generation would meet the carbon capture process energy requirements.

Typically, CO_2 capture from the flue gas of a post-combustion process for a conventional coal technology plant has been thought to employ absorption using mono-ethanol amine (MEA), a chemical solvent that is commercially available and widely used. The CO_2 capture plant would consist of flue gas preparation, CO_2 absorption, CO_2 stripping, and CO_2 compression.

For an MEA CO_2 capture process, an auxiliary load in the range of 20 to 30 percent of gross plant output can be expected which would require additional capacity of 30 to 40 of gross plant output in order to maintain project required net capacity. The capital requirements for CO_2 capture addition would need to include both the CO_2 capture equipment and the capital required for additional capacity.

A new and developing alternative to the MEA CO_2 capture process is a chilled ammonia CO_2 absorption process, currently under development by Alstom. Compared to the MEA absorption process, the chilled ammonia absorption process appears to have the potential to significantly reduce the energy and capital requirements to achieve post-combustion CO_2 capture. A schematic of this process is shown in Figure 3-7. The description provided here is based on data presented in a position paper published by Alstom.[1]

For a CO_2 capture process employing Alstom's chilled ammonia absorption, the flow would begin at the flue gas discharge from the plant FGD. First, the flue gas would be cooled from a typical FGD exit temperature of 120 to 140° F to approximately 35° F. Flue gas cooling can be achieved by cooling towers and mechanical chillers. The power consumed by the cooling process is estimated by Alstom to consume one to two percent of the gross plant output. Reducing the temperature of the flue gas would have the effect of condensing out saturated water in the flue gas introduced by the FGD and any residual contaminants remaining in the flue gas. In addition, cooling the flue gas to a lower

[1] "Chilled Ammonia Process for CO2 Capture," Alstom, November 2006.

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temperature will reduce the volume of the flue gas (a volume reduction of approximately 33 percent will occur when cooled from 140° F to 32° F). The reductions in mass flow rate resulting from moisture removal and volumetric flow rate of the flue gas may reduce the size, energy requirements and capital costs of downstream capture equipment.

Once the flue gas is cooled, the CO_2 absorption takes place in an absorption module similar to an FGD absorption module. A slurry containing a mixture of dissolved and suspended ammonium carbonate and ammonium bisulfate is discharged in the module against an upward flow of flue gas. More than 90 percent of the CO_2 contained in the flue gas is absorbed in the slurry. Any ammonia transferred to the flue gas by the absorption process would be captured by a cold-water wash process and returned to the slurry. After CO_2 absorption, the slurry is regenerated in a high pressure regenerator. Regenerating the slurry at a high pressure reduces the energy requirements for CO_2 compression once it is stripped from the slurry. CO_2 is stripped from the slurry by thermal energy addition which is obtained from a heat exchanger prior to injection in to the regenerator and heat addition by a reboiler in the regenerator. Any ammonia or water vapor contained in the CO_2 gas stream stripped from the slurry is removed in a cold-water wash at the top of the absorber.

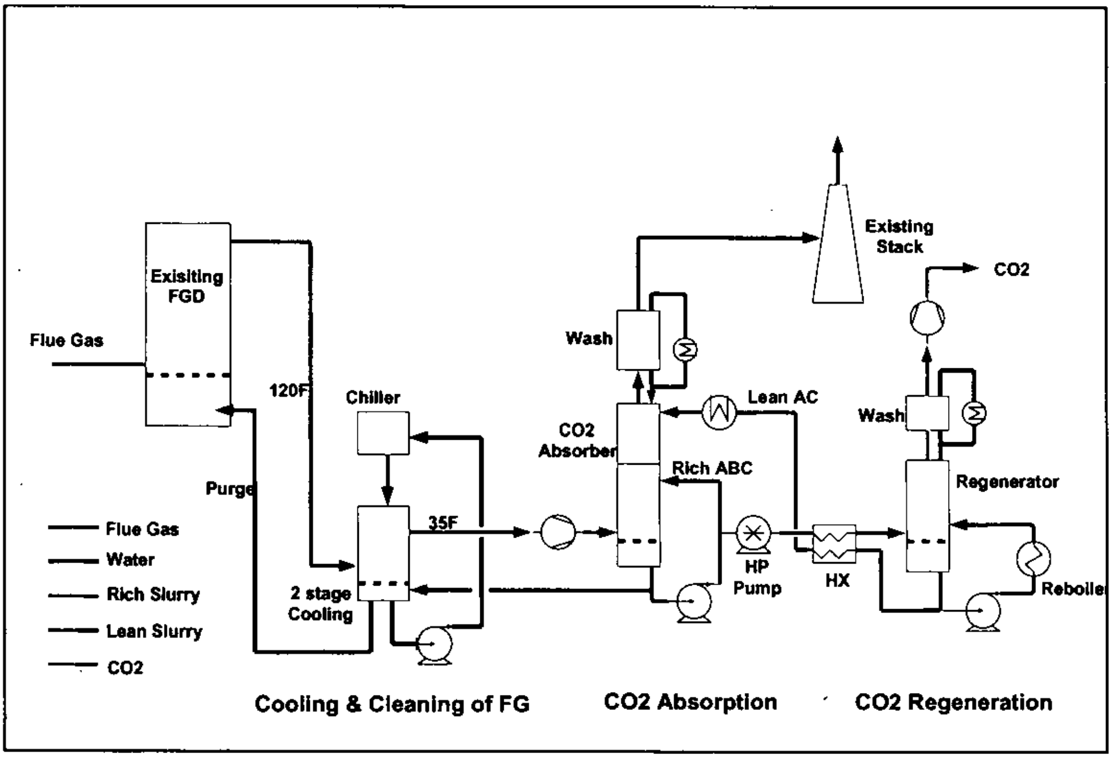

Figure 3-7. Schematic of Ammonia-Based CO_2 Capture System.

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The primary advantage of the Alstom chilled ammonia CO_2 absorption process compared to MEA is the reduced operating energy requirements and capture costs. In a reference study prepared by Alstom comparing their ammonia absorption process to an MEA absorption process, the ammonia absorption process had a significantly reduced affect on net plant output and net plant heat rate. In addition, the cost of capture in dollar per avoided ton of CO_2 was less than half that expected with MEA.

Alstom's chilled ammonia CO_2 absorption process is still in development. Alstom projects the offering of a commercial product before the end of 2011. An Alstom press release dated October 2, 2006, announced a collaborative project between Alstom, the Electric Power Research Institute (EPRI) and We Energies to build a 5 MW pilot plant that will demonstrate the CO_2 capture process. The facility will be constructed at a power plant owned by We Energies in Pleasant Prairie, Wisconsin and is expected to be commissioned in mid-2007. The demonstration facility will give Alstom and EPRI the opportunity to evaluate the process on a larger commercial scale moving from bench scale testing.

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4.0 IGCC Technologies and Industry Activity

This section contains a summary-level description of IGCC technologies, including a review of IGCC experience and a discussion of the issues related to commercializing the technology.

Reliability is expected to be lower for an IGCC plant than for a PC or CFB plant with respect to producing electricity from coal. IGCC plants without spare gasifiers are expected to achieve long-term annual availabilities in the 80 to 85 percent range on coal versus approximately 90 percent for PC and CFB. IGCC availability on coal during initial startup and the first several years of operation is expected to be significantly lower. A generation plant that uses IGCC technology could increase the availability by firing the combined cycle portion of the plant on a backup fuel such as natural gas when syngas is not available from coal gasification. The cost, availability, and air emissions of backup fuel firing may limit or prevent its use. Currently, natural gas is not available at FGPP. The installation of a relatively long natural gas pipeline would be required if natural gas were to be used as a backup fuel. Large capital cost would be required for the installation of a natural gas pipeline to FGPP. Additional capital would also be required for the installation all associated equipment required to operate the combined cycle on natural gas. These large capital requirements would not be justified by the incremental benefit of increased plant availability with higher cost natural gas as a backup fuel. Because of this, the use of natural gas as a backup fuel for an IGCC plant at FGPP would not be economically feasible. Likewise, using fuel oil as a backup fuel to enhance syngas production reliability would also be prohibitively expensive and logistically cumbersome.

Cost, schedule, and plant availability issues cause IGCC projects to have higher financial risk than conventional PC or CFB power generation projects. Details regarding the guarantee levels for cost, schedule, and performance; the associated liquidated damages clauses and risk premium; and availability assurances are not well defined at this time. It is expected that the standards for contractual arrangements between owners and constructors will evolve based on the experiences of the next generation of IGCC project development.

4.1 Gasification Technologies and Suppliers

Gasification is a mature technology with a history that dates back to the 1800s. The first patent was granted to Lurgi GmbH in Germany in 1887. By 1930, coal gasification had become widespread and in the 1940s, commercial coal gasification was used to provide "town" gas for streetlights in both Europe and the United States.

Currently, there are four main types of gasifiers:

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- Entrained flow
- Fixed bed
- Fluidized bed
- Transport bed

The following listing includes the most notable technology suppliers by type:

- Entrained Flow Gasifiers:
  - ConocoPhillips (COP) (E-Gas, formerly Global Energy, originally Dow-Destec).
  - General Electric (GE) (formerly ChevronTexaco, originally Texaco).
  - Mitsubishi Heavy Industries (MHI).
  - Shell.
  - Siemens GSP (formerly Noell).
- Fixed Bed (or Moving Bed) Gasifiers:
  - BGL (slagging, Global Energy, formerly British Gas Lurgi).
  - Lurgi (dry bottom).
- Fluidized Bed Gasifiers:
  - Carbona (formerly Tampella).
  - HTW (formerly High Temperature Winkler).
  - KRW.
  - Lurgi.
- Transport Bed Gasifiers:
  - KBR.

Entrained flow gasifiers have been operating on oil feedstock since the 1950s and on coal and petcoke feedstock since the 1980s. Entrained flow gasifiers operate at high pressure and temperature, have very low fuel residence times, and have high feedstock capacity throughputs. Fixed bed gasifiers have operated on coal feedstock since the 1940s. Compared to entrained flow gasifiers, fixed bed gasifiers operate at lower pressure and temperature, have much longer fuel residence times, and have lower capacity throughputs. Fluidized bed gasifiers have operated on coal since the 1920s. Compared to entrained flow gasifiers, fluidized bed gasifiers operate at lower pressure and temperature, use air instead of oxygen, have longer fuel residence times, and have lower capacity throughput. Transport bed gasifiers have only recently been tested on a small scale. Compared to entrained flow gasifiers, transport gasifiers operate at lower pressure and temperature, use air instead of oxygen, have longer fuel residence times, and have lower capacity throughput.

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Limestone is fed with coal to fluidized bed and transport bed gasifiers for capturing sulfur as calcium sulfide (CaS), which is typically oxidized to $CaSO_4$ for landfill disposal. Entrained flow and fixed bed gasifiers treat the syngas from gasification to remove the sulfur-containing constituents as elemental sulfur or sulfuric acid (H_2SO_4), which can be sold. The ash from fluidized bed, transport bed, and dry bottom fixed bed gasifiers is leachable and is typically landfilled. Entrained flow and slagging fixed bed gasifiers operate above the ash fusion temperature and produce a nonleachable slag that can be sold.

Entrained flow and fixed bed gasifiers generally use high purity oxygen as the oxidant. Fluidized bed and transport gasifiers use air instead of oxygen. Since high purity oxygen does not contain the large concentration of nitrogen present in air, equipment size can be reduced commensurately. Higher gasifier operating pressures are also more economical for the smaller gas flow rates and equipment size associated with high purity oxygen use. Entrained flow gasifiers have higher operating temperatures and lower residence times than fluidized and transport bed gasifiers. These conditions typically require the use of high purity oxygen for entrained flow gasifiers. An oxygen purity of 95 percent by volume is the optimum for entrained flow gasifiers producing syngas for combustion turbine fuel. Oxygen purities of 98 percent or higher are required when the syngas is used to produce chemicals and liquid fuels.

Entrained flow gasifiers are relatively new technologies compared to fluidized bed and fixed bed gasifiers. Entrained flow gasifiers have been operating successfully on solid fuels since the mid-1980s to produce chemicals and since the mid-1990s to produce electricity in four commercial-scale IGCC demonstration plants, located in Europe (two units) and the US (two units).

Transport bed gasification technology is a recent development that has not yet been demonstrated on a commercial scale. The Southern Company and KBR have been testing a 30 tpd air-blown transport reactor integrated gasification (TRIG) system at the US DOE-funded Power Systems Development Facility (PSDF) at Wilsonville, Alabama. TRIG employs KBR catalytic cracking technology, which has been used successfully for more than 50 years in the petroleum refining industry. In 2004, the US DOE awarded \$235 million to the Southern Company and the Orlando Utilities Commission (OUC) to build a 285 MW IGCC Plant at the Stanton Energy Center in Florida to demonstrate TRIG combined cycle technology under the Clean Coal Power Initiative (CCPI) program. The total cost of this plant is estimated to be \$792 million. The proposed plant will gasify subbituminous coal. Southern Company estimates that the plant heat rate will be

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approximately 8,400 Btu/kWh (HHV coal).[1] The demonstration plant is scheduled to start up in or after 2010. Results from this commercial-scale demonstration plant should determine whether TRIG technology will be competitive with entrained flow gasifier technology.

At this time, based on their characteristics and level of development, oxygen-blown entrained flow gasifiers are the best choice for high capacity gasification for power generation.

4.2 Entrained Flow Gasification Process Description

A typical IGCC process flow diagram is shown on Figure 4-1.

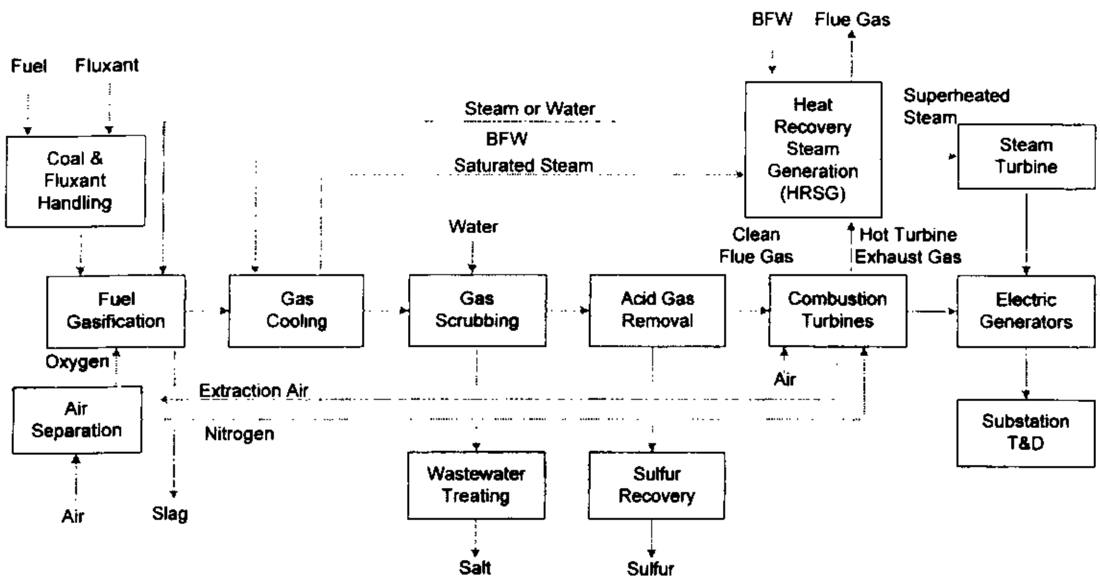

Figure 4-1. IGCC Process Flow Diagram

Gasification consists of partially oxidizing a carbon-containing feedstock (solid or liquid) at a high temperature (2,500 to 3,000° F) to produce a syngas consisting primarily of CO and hydrogen. A portion of the carbon is completely oxidized to carbon dioxide (CO_2) to generate sufficient heat required for the endothermic gasification reactions. (The CO_2 proportion in the syngas from the gasifier ranges from 1 percent for the dry feed Shell gasifier to more than 15 percent for the slurry feed COP and GE gasifiers.) The gasifier operates in a reducing environment that converts most of the sulfur in the feed to hydrogen sulfide (H_2S). A small amount of sulfur is converted to carbonyl sulfide

[1] At average ambient conditions, and assumed new and clean.

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(COS). Some sulfur remains in the ash, which is melted and then quenched to produce slag. Other minor syngas constituents include ammonia (NH_3), hydrogen cyanide (HCN), hydrogen chloride (HCl), and entrained ash, which contains unconverted carbon. In IGCC applications, the minimum gasifier pressure is typically 450 to 550 psia. This pressure is determined by the combustion turbine syngas supply pressure requirements. GE gasifiers operate at higher pressures, up to 1,000 psia, and the excess syngas pressure is let down in an expander to produce additional power.

A fluxant may need to be fed with the coal to control the slag viscosity so that it will flow out of the gasifier. Fluxant addition is less than 2 percent of the coal feed. The fluxant can be limestone, PC boiler ash, or, in some cases, dirt. The required fluxant composition and proportion will vary with the coal feed composition. The gasification process operators must know the feed coal composition and make fluxant adjustments when the coal composition changes. Too little fluxant can allow excessive slag to accumulate in the gasifier, which could damage the refractory and eventually choke the gasifier. Too much fluxant can produce long cylindrical slag particles instead of small slag granules when the slag is quenched in the lockhopper. These long thin slag particles will plug up the slag lockhopper.

Solid fuel feeds to the gasifier can be dry or slurried. Solid fuels slurried in water do not require the addition of steam for temperature moderation. While slurries typically use water, oil can also be used. Steam is added to the oxygen as a temperature moderator for dry solid feed gasifiers, solid feeds slurried in oil, and oil feed gasifiers.

Entrained flow gasifiers use oxygen to produce syngas heating values in the range of 250 to 300 Btu/scf on an HHV basis[1]. Oxygen is produced cryogenically by compressing air, cooling and drying the air, removing CO_2 from the air, chilling the feed air with product oxygen and nitrogen, reducing the air pressure to provide autorefrigeration and liquefy the air at -300° F, and separating the liquid oxygen and liquid nitrogen by distillation. Air compression consumes a significant amount of power, between 13 and 17 percent of the IGCC gross power output.

Hydrogen in syngas prevents the use of dry low NO_x (DLN) combustors in the combustion turbines. The dilution of the syngas to reduce flame temperature is required for NO_x control. Syngas is typically diluted by adding water vapor and/or nitrogen. Water vapor can be added to the syngas by evaporating water using low level heat. Nitrogen can be added by compressing excess nitrogen from the air separation unit (ASU) and adding it to the syngas either upstream of the combustion turbine or by injection into the combustion turbine. Syngas dilution for NO_x control increases the mass

[1] Comparatively, pipeline quality natural gas has a heating content of about 950 to 1,000 Btu/scf (HHV).

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flow through the combustion turbine, which also increases power output. GE combustion turbines inject this diluent nitrogen separately from the syngas into the same ports used for steam or water injection. For MHI and Siemens Power Generation (SPG – formerly known as Siemens Westinghouse or SW) combustion turbines, diluent nitrogen is premixed with the syngas. The nitrogen supply pressure required for injection into a GE 7FB is 405 psia versus 450 to 500 psia for mixing with the syngas for the MHI 501F and the SPG SGT6-5000F (previously referred to as the SW 501FD). The diluted syngas has a heat content of 140 to 150 Btu/scf. However, the mass flow of the diluted syngas is eight times that of natural gas, which increases the combustion turbine power output by up to 16 percent, when no air is extracted for the ASU. A portion of the combustion turbine compressed air may be extracted for feed to the ASU. The ASU and combined cycle are integrated by the nitrogen and air exchanges. Extracting compressed air from the combustion turbine improves overall efficiency, but it adds complexity to the process, including longer startup periods, if there is no separate source of startup compressed air. The prevailing thought is to minimize or avoid compressed air integration.

The raw hot syngas is cooled by the boiler feedwater from the HRSG to a temperature suitable for cleaning. The syngas cooling process generates steam. The steam quantities and pressures vary with the gasification process design. Gasification steam is subsequently integrated into the steam cycle.

Before the raw syngas enters the combustion turbine combustor, the H_2S, COS, NH_3, HCN, and particulates must be removed. Cooled syngas is scrubbed to remove NH_3, water soluble salts, and particulates. Syngas may also be filtered to remove additional particulates. COS in the syngas is hydrolyzed by a catalyst to H_2S, which is removed from the syngas by absorption in a solvent. This absorption process is called acid gas removal (AGR).

Syngas is filtered in ceramic candle filters at the Buggenum and Puertollano IGCC plants. At the Wabash IGCC plant, syngas was initially filtered in ceramic candle filters; later, the filter elements (candles) were changed to sintered metal. The syngas filters at the Buggenum, Puertollano, and Wabash plants are located upstream of the AGR. At the Polk County IGCC plant, syngas is filtered in cartridge filters downstream from the AGR.

The H_2S that is removed from the syngas by absorption in a solvent is desorbed as a concentrated acid gas when the solvent is regenerated, by lowering its pressure and increasing its temperature. Descriptions of commercial AGR systems are provided in Section 4.9. The acid gas stream is typically converted to elemental sulfur in the Claus sulfur recovery process, although it is also possible to produce sulfuric acid.. The primary chemical reaction in the Claus process is the reaction of H_2S and SO_2 to produce

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elemental sulfur and water. This reaction requires a catalyst and is performed in two stages. The SO_2 is produced by oxidizing (burning) one third of the H_2S in the feed gas. External fuel is only needed to initially heat up the Claus thermal reactor and initiate combustion of the acid gas. Under normal operation, the oxidation of H_2S provides sufficient heat to maintain the reaction. The sulfur is formed as a vapor; the S_2 form of sulfur reacts with itself to produce S_6 and S_8, which are subsequently condensed. This condensed liquid sulfur is separated from the residual gas and stored in a pit at 275° to 300° F. As required, the liquid sulfur is pumped from the pit to railcars for shipment. Solid sulfur can be produced in blocks or pellets by cooling the liquid sulfur to ambient temperature. The residual (tail gas) is primarily CO_2 and nitrogen, which are compressed and reinjected into the syngas upstream of the AGR.

4.3 Gasification Technology Suppliers

Today, there are three major entrained flow coal gasification technology suppliers:

- COP, which licenses E-Gas technology that was developed by Dow. COP purchased this technology from Global Energy in August 2003.
- GE, which purchased Texaco gasification technology from ChevronTexaco in June 2004. GE offers both Quench and Radiant (high temperature heat recovery [HTHR]) cooler gasifiers.
- Shell, which developed its gasification technology in conjunction with Prenflo. Prenflo technology is no longer licensed.

The other entrained flow gasifiers listed in Section 4.1 are not currently strong competitors in the utility-scale IGCC market because of the relative maturity of the technology. MHI is developing an air-blown, two-stage entrained flow gasifier with dry feed. MHI intends to demonstrate this technology at a 250 MW project in Japan. Siemens (formerly Sustec GSP, FutureEnergy, and Noell) has one small gasification plant (Schwarze Pumpe, 200 MW_{th} methanol and power cogeneration). Its technology has been geared toward biomass and industrial processing on a smaller scale, but it seems to be making an entry into the utility-scale power generation market. According to a May 2006 press release, Siemens plans to build a 1,000 MW coal IGCC in Germany as a first step to commercializing its newly acquired IGCC technology. Multiple other GSP coal gasification projects are currently being implemented, including three in China that wil produce ammonia and methanol.

The COP and GE gasifiers are refractory lined with coal-water slurry feed. In the late 1970s, Shell and Krupp-Koppers jointly developed a waterwall type gasifier with

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dry, pulverized coal feed specifically for IGCC power generation for a 150 ltpd demonstration plant near Hamburg, West Germany. During the 1990s, Shell and Krupp-Koppers licensed their gasification technology separately. The Puertollano, Spain IGCC plant, which was built in the mid-1990s, uses Krupp-Kopper's Prenflo gasification technology. In the late 1990s, Krupp-Koppers merged with Uhde, and Uhde reached an agreement with Shell to license Shell gasification technology and no longer market the Prenflo gasification process. Uhde has incorporated its Prenflo experience into Shell's coal gasification process technology.

Each of the three commercial, entrained flow coal gasification technologies generates similar syngas products. All three gasifiers react the coal with oxygen at high pressure and temperature to produce a syngas consisting primarily of hydrogen and CO. The raw syngas from the gasifier also contains CO_2, water, H_2S, COS, NH_3, HCN, and other trace impurities. The syngas exits the gasifier reactor at approximately 2,500 to 2,900° F.

Each of the COP, GE, and Shell gasification processes cools the hot syngas from the gasifier reactor differently. In the COP process, the hot syngas is partially quenched with coal slurry, resulting in a second stage of coal gasification. The raw syngas from the COP gasifier may also contain methane and products of coal devolatilization and pyrolysis because of its two-stage gasification process. The partially quenched syngas is cooled with recycled syngas to solidify the molten fly slag and then further cooled to produce HP steam in a vertical shell and tube heat exchanger. (Syngas flow is down through the tubes. Boiler water and steam flow is up through the shell side.) Unconverted coal is filtered from the cooled syngas and recycled to the gasifier first stage. GE has two methods for cooling the hot syngas from the gasifier: radiant cooling to produce HP steam via HTHR and water quench with low-pressure (LP) steam generation. In the Shell process, hot syngas is cooled with recycled syngas to solidify the molten fly slag and then further cooled in a convective cooler to produce high-temperature steam.

The cooled, raw syngas is cleaned by various treatments, including filtration, scrubbing with water, catalytic conversion, and scrubbing with solvents, as discussed in Section 4.9. The clean syngas that is used as combustion turbine fuel contains hydrogen, CO, CO_2, water, and parts per million (ppm) concentrations of H_2S and COS.

4.4 Gasifier Technology Selection

Table 4-1 provides process design characteristic data for the COP, GE, and Shell gasification technologies for systems that would generally be considered for a facility of this size and type. The Shell gasification technology has the highest cold gas efficiency,

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because the gasifier feed coal is injected into the gasifier dry, whereas with the COP and GE gasifiers, the feed is a slurry of coal in water. However, the Shell dry feed coal gasification process has a higher capital cost. Cooling the hot syngas to produce HP steam also contributes to higher IGCC efficiency, but with a higher capital cost. Shell and COP generate HP steam from syngas cooling. GE offers both HP steam generation using Radiant syngas coolers and LP steam generation using its Quench process, which has a significantly lower capital cost than the Radiant. The COP and GE gasifiers are refractory lined, while the Shell gasifier has an inner water tube wall (membrane). The refractory-lined gasifiers have a lower capital cost, but the refractory requires frequent repair and replacement. The COP and GE gasifier burners typically require more frequent replacement than the Shell gasifier burners.

Table 4-1. Comparison of Key Gasifier Design Parameters

Technology	COP	GE Quench	GE HTHR	Shell
Gasifier Feed Type	Slurry	Slurry	Slurry	Dry N_2 Carrier
Gasifier Burners	Two Stage: First Stage--Two horizontal burners Second Stage--One horizontal feed injector w/o O_2	Single Stage--One vertical burner	Single Stage--One vertical burner	Single Stage--Four to eight horizontal burners
Gasifier Vessel	Refractory lined	Refractory lined	Refractory lined	Waterwall membrane
Syngas Quench	Coal Slurry and Recycle Gas	Water	None	Recycle Gas
Syngas Heat Recovery	Firetube HP WHB	Quench LP WHB	Radiant HP WHB	Watertube HP WHB
Coal Cold Gas Efficiency, HHV	71 to 80 percent	69 to 77 percent	69 to 77 percent	78 to 83 percent
Coal Flexibility	Middle	Low	Low	High
Capacity, stpd	3,000 to 3,500	2,000 to 2,500	2,500 to 3,000	4,000 to 5,000

WHB--Waste Heat Boiler

It is worth mentioning gasifier sizing issues with respect to the Shell and GE Quench technologies. Shell has stated that its maximum gasifier capacity is 5,000 stpd of dried coal, which is large enough to supply syngas to two GE 7FB or Siemens SGT6-5000F combustion turbines. GE offers gasifiers in three standard sizes: 750, 900, and 1,800 ft^3. The largest Quench gasifier that GE currently offers is 900 ft^3. The maximum

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capacity of this gasifier is approximately 2,500 tpd of as-received coal and does not produce enough syngas for a GE 7FB or Siemens SGT6-5000F combustion turbine. The largest Radiant gasifier that GE currently offers is 1,800 ft^3, which will supply sufficient syngas for a GE 7FB or Siemens SGT6-5000F combustion turbine. COP currently offers a gasifier that will supply sufficient syngas for a GE 7FB or Siemens SGT6-5000F combustion turbine.

Overall, energy conversion efficiencies for IGCC plants vary with the gasification technology type, system design, level of integration, and coal composition. The gasifier efficiency of converting the coal fuel value to the syngas fuel value (after sulfur removal) is known as the cold gas efficiency, which is generally expressed in HHV. The values for cold gas efficiency in Table 4-1 are indicative of the range of achievable performance for coal and petcoke. Cold gas efficiency for the Shell dry coal feed process is about 3 percent higher than the coal-water slurry feed gasification processes for low moisture coal. This difference increases with coal moisture content. HP steam generation from syngas cooling increases IGCC efficiency by about 2 percent over that of water quench.

4.5 Commercial IGCC Experience

There have been approximately 18 IGCC projects throughout the world, as listed in Table 4-2. Of these, fifteen were based on entrained flow gasification technology. Nine of the projects were coal based, two are petcoke based, one is sludge based, and the other six are oil based. Two of the coal-based IGCC plants, Cool Water in California and the Dow Chemical Plaquemine Plant in Louisiana, were small demonstration projects and have been decommissioned. Another small coal IGCC demonstration project was Sierra Pacific's Piñon Pine Project in Nevada. This project, based on KRW fluidized bed technology, was not successful.

Of the six operating coal IGCC plants, one is a 40 MW plant that coproduces methanol using a Noell gasifier, one is a 350 MW lignite cogeneration plant that has 26 Lurgi fixed bed gasifiers, and four are commercial-scale, entrained flow gasification demonstration projects (ranging in capacity from 250 to 300 MW) that are located in Florida, Indiana, The Netherlands, and Spain. The Wabash Indiana IGCC plant did not operate for an extended period in 2004 and 2005 because of contractual problems, but is currently back in operation. Design data for these four demonstration plants are listed in Table 4-3. None of these demonstration units is of the same capacity scale as that required for the FGPP units.

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Table 4-2. IGCC Projects – All Fuels

Owner - Location	Year[1]	MW	Application	Fuel	Gasifier
SCE Cool Water[2] – USA (CA)	1984	120	Power	Coal	Texaco (GE)
Dow LGTI Plaquemine – Plaquemine[2] - USA (LA)	1987	160	Cogen	Coal	COP (Destec)
Nuon Power – Netherlands	1994	250	Power	Coal	Shell
PSI/Global Wabash – USA (IN)	1995	260	Repower	Coal	E-Gas (COP)
TECO Polk County – USA (FL)	1996	250	Power	Coal	Texaco (GE)
Texaco El Dorado[3] – USA (KS)	1996	40	Cogen	Petcoke	Texaco (GE)
SUV - Czech Republic	1996	350	Cogen	Coal	Lurgi[5]
Schwarze Pumpe - Germany	1996	40	Power/ Methanol	Lignite	Noell
Shell Pernis Refinery - Netherlands	1997	120	Cogen/Hydrogen	Oil	Shell
Elcogas - Spain	1998	300	Power	Coal/ Petcoke	Prenflo
Sierra Pacific[4] – USA (NV)	1998	100	Power	Coal	KRW[6] - Air
ISAB Energy - Italy	1999	500	Power/Hydrogen	Oil	Texaco (GE)
API - Italy	2000	250	Power/Hydrogen	Oil	Texaco (GE)
Delaware City Refinery - USA (DE)	2000	180	Repower	Petcoke	Texaco (GE)
Sarlux/Sara Refinery - Italy	2000	550	Cogen/Hydrogen	Oil	Texaco (GE)
ExxonMobil - Singapore	2000	180	Cogen/Hydrogen	Oil	Texaco (GE)
FIFE - Scotland	2001	120	Power	Sludge	BGL[5]
NPRC Negishi Refinery - Japan	2003	342	Power	Oil	Texaco (GE)

(1)First year of operation on syngas.
(2)Retired.
(3)The El Dorado Refinery is now owned by Frontier Refining.
(4)Not successful.
(5)Fixed bed.
(6)Fluidized bed.

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Table 4-3. Coal-Based IGCC Demonstration Plants [1]				
Project	**Nuon Power**	**Wabash** [3]	**TECO Polk County** [4]	**Elcogas**
Location	Buggenum, Netherlands	Indiana	Florida	Puertollano, Spain
Technology	Shell	E-Gas (COP)	Texaco (GE)	Prenflo (Krupp)
Startup Year	1994	1995	1996	1998
Net Output, design, MW	252	262	250	300[5]
HHV Efficiency, net design, percent	41.4	37.8	39.7	41.5
Height, ft	246	180	295	262
Fuel, design	Coal	Coal	Coal	50% coal/50% petcoke
Fuel Consumption, tpd	2,000	2,200	2,200	2,600
Fuel Feed	Dry N_2 lockhopper	Wet slurry	Wet slurry	Dry N_2 lockhopper
Syngas HHV, Btu/scf	300	276	266	281
CTG Model	Siemens V94.2	GE 7FA	GE 7FA	Siemens V94.3
Firing temperature, °F	2,012	2,300	2,300	2,300
Combustors	Twin vertical silos	Multiple cans	Multiple cans	Twin horizontal silos
CTG Output, design, MW	155	192	192	200
STG Output, design, MW	128	105	121	135
Auxiliary Power, design, MW	31	35.4	63	35
Net Output, design, MW	252	262	250	300
Net Output, achieved, MW	252	252	250	300
NPHR, design, Btu/kWh HHV	8,240	9,030	8,600	8,230
NPHR, achieved, Btu/kWh HHV [2]	8,240	8,600 - Adjusted for HRSG feedwater heaters	9,100 - Adjusted for gas/gas heat exchanger	8,230
ASU Pressure, psi	145	72.5	145	145
Nitrogen Usage	Syngas Saturator	Vented	CTG NO_x Control	Syngas Saturator

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Table 4-3. Coal-Based IGCC Demonstration Plants [1]

Project	Nuon Power	Wabash [3]	TECO Polk County [4]	Elcogas
NO_x Control	Saturation and N_2 dilution	Saturation + steam injection	N_2 dilution to combustors	Saturation and N_2 dilution
NO_x, 6% O_2, mg/Nm^3	25	100 to 125	100 to 125	150
Slag Removal	Lockhopper	Continuous	Lockhopper	Lockhopper
Recycle Gas Quench	50% of gas, to 1,650° F	Some in second stage	None	67% of gas, to 1,475° F
Integration				
Water/steam	Yes	Yes	Yes	Yes
N_2 Side ASU/CTG	Yes	No	Yes	Yes
Air Side ASU/CTG	Yes	No	No	Yes
Add Air Compressor	Yes	Yes	Yes	No
Gas Cleanup				
Particulate Removal	Cyclone/Ceramic candle filter	Sintered metal candle filter	Water wash	Ceramic candle filter
Chloride Removal	Water scrubbing	Water scrubbing	Water scrubbing	Water scrubbing
COS Hydrolysis	Yes	Yes	Retrofit in 1999	Yes
AGR Process	Sulfinol	MDEA	MDEA	MDEA
Sulfur Recovery	Claus + SCOT TGR	Claus + Tail Gas Recycle	H_2SO_4 Plant	Claus + Tail Gas Recycle
SO_2, 6% O_2, mg/Nm^3	35	40	40	25

[1] Information taken from "Operating Experience and Improvement Opportunities for Coal-Based IGCC Plants," Holt, Neville from *Science Reviews – Materials at High Temperatures*, Spring 2003. Additional footnotes are by Black & Veatch.

[2] Achieved NPHR are instantaneous values from performance testing. Long term annual average heat rates vary with degradation and dispatch profile.

[3] Wabash NPO and NPHR reported as 261 MW and 8,600 Btu/kWh in "The Wabash River Coal Gasification Repowering Project, an Update", USDOE, September 2000.

[4] TECO NPO and NPHR reported as 250 MW and 9,650 Btu/kWh in "Tampa Electric Integrated Gasification Combined Cycle Project", USDOE, June 2004.

[5] Based on ISO conditions. Site specific design NPO was 283 MW, with probable further derate due to higher ASU auxiliary load.

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Each of the four projects was a government-subsidized IGCC demonstration, two in the United States and two in Europe. Each of these IGCC plants consists of a single train (one ASU, one gasifier, one gas treating train, and one combined cycle consisting of one CTG, one HRSG, and one STG). Wabash has a spare gasifier.

Table 4-3 also summarizes the integration in each plant. Basically, there are three major areas for potential integration:

- Water and steam between the power generation area and the gasification island. High- and low-level heat rejection from the gasification process is utilized to produce combined cycle power.
- The nitrogen side of the ASU and CTG--Waste nitrogen is mixed with the syngas to reduce NO_x formation and to increase power output.
- The air side of the ASU and the CTG--Air is extracted from the CTG compressor to reduce the auxiliary power and increase efficiency.

Figure 4-2 depicts potential areas of integration. The European plants have been highly integrated, partly in response to higher fuel prices, while the US plants have been less integrated. Both the Nuon Power Buggenum, Netherlands plant and the Elcogas Puertollano, Spain plant experienced operating difficulties as a result of the highly integrated design. EPRI has suggested that such high integration should be avoided in future designs.

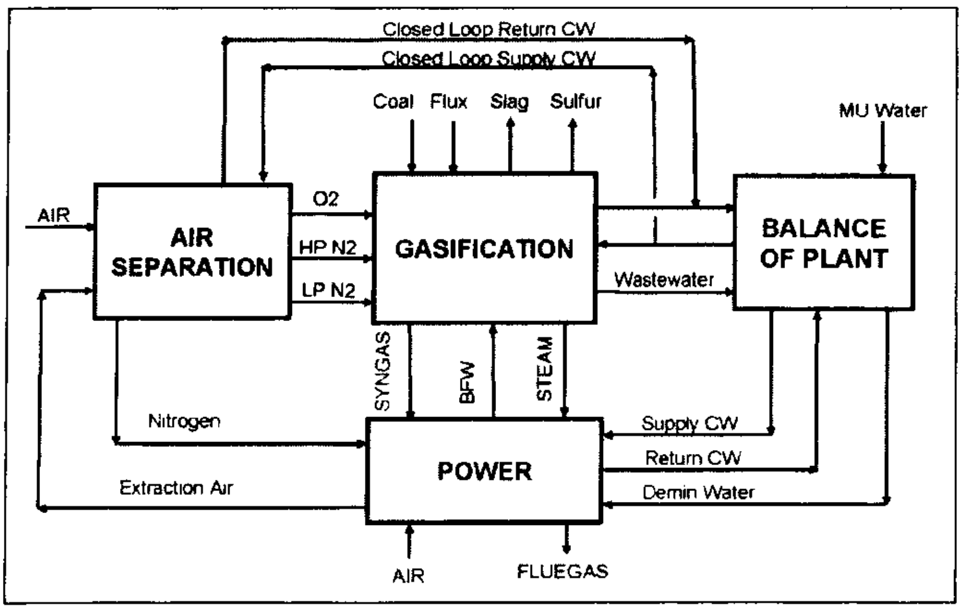

Figure 4-2. Potential Areas for Integration

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The operation of these four commercial coal-fueled IGCC plants has adequately demonstrated capacity, efficiency, and environmental performance, but uncertainty remains regarding availability, reliability, and cost. The complexity and the relative immaturity of the IGCC process increase opportunities for deficiencies in design, vendor-supplied equipment, construction, operation, and maintenance. The high risks of cost overruns and low availability have presented obstacles to the development of nonsubsidized coal-fueled IGCC projects. At present, there are several coal-based IGCC projects being developed in the United States that have or expect to receive subsidies.

4.6 Fuel Characteristics Impact on Gasifier Selection

There are three general coal feedstocks typically considered for IGCC projects: Appalachian, Illinois, and Powder River Basin (PRB). Petcoke is a fourth solid fuel feedstock that is frequently considered for IGCC applications. Petcoke may be a lower cost fuel, but it is not as readily obtainable as coal. Historically, anthracite and lignite coals have not been seriously evaluated for IGCC projects, nor have waste coals such as gob (coal mine waste) and culm (waste produced when anthracite is mined and prepared for market, primarily rock and some coal).

Coal-based operating experience has been focused almost exclusively on bituminous coals (e.g., Pittsburgh No. 8 and Illinois No. 6), and there is also extensive experience with petcoke. Subbituminous (i.e., PRB) coals have been tested only in a limited fashion, but because of the nature of the US coal market and the abundance of PRB coal, there is strong interest in using it for IGCC applications. Typical design values for the coals generally considered for IGCC are listed in Table 4-4.

Table 4-4. As-Received Coal Properties of Typical IGCC Coals

Fuel	Pittsburgh No. 8	Illinois No. 6	PRB
Heat Content, Btu/lb (HHV)	12,300	10,200	8,400
Moisture, percent	8.0	14.1	29.4
Ash, percent	12.0	15.7	6.0
Sulfur, percent	4.0	4.3	0.34

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In the GE gasification process, all of the inherent water in the coal and the liquid water in the slurry must be evaporated in the gasifier by combusting more CO to CO_2, which results in a lower cold gas efficiency than the COP and Shell gasification processes. For low moisture fuels, such as the one in this study, the GE process can be very cost competitive. COP is able to attain a higher cold gas efficiency than GE through use of a full slurry quench

4.7 IGCC Performance and Emissions Considerations

IGCC net power output decreases with increasing ambient temperature, but this reduction is less than that of a natural gas combined cycle (NGCC) plant. The IGCC plant auxiliary power consumption also increases slightly with the ambient temperature for ASU air compression and cooling tower fans, but this is offset by higher combustion turbine output.

The CO and NO_x emissions estimates were based on CTGs firing syngas with nitrogen dilution, but without an SCR or CO oxidation catalyst in the HRSG:

- 25 ppmvd CO in the CTG exhaust gas.
- 15 ppmvd NO_x (at 15 percent by volume O_2) in the CTG exhaust gas.

The SO_2 emissions estimate was based on a 25 ppm molar concentration of sulfur as H_2S and COS in the syngas. Sulfur removal efficiencies of greater than 99 percent are achievable for an IGCC plant processing high sulfur coal or petcoke, depending on the solvent selected. Flaring during startups, shutdowns, and upsets can result in significant SO_2 emissions. Sour gas flaring during upsets cannot be eliminated, but can be minimized by appropriate process design and operating procedures.

Syngas will flow through sulfur impregnated carbon, which is estimated to lower the syngas mercury concentration below 5 ppb by weight. Up to 40 percent of the mercury in the coal may be removed upstream of the sulfur impregnated carbon by scrubbing, which would reduce the mercury concentration at the inlet of the sulfur impregnated carbon to 30 to 42 ppb by weight. Eastman Chemical Company's coal gasification plant has used sulfur impregnated carbon beds for mercury removal since its startup in 1993. Eastman reports 90 to 95 percent mercury removal with a bed life of 18 to 24 months.

4.8 Gasification Wastewater Treatment

There are two general categories of plant wastewater:

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- Streams that contain metals from the as-received coal, referred to as gasification wastewater streams.
- Streams that do not contain these metals, referred to as balance-of-plant wastewater streams.

The gasification wastewater streams will be combined and treated separately from the balance-of-plant wastewater streams. Accurate specification of the process wastewater composition has been a problem on other operating gasification plants because of the wide variation in coal composition. The wastewater treatment design should accommodate variations in wastewater composition.

There are three basic options for treating gasification wastewater streams:

1. Open Discharge Concept, which consists of metals precipitation, followed by biological treatment to produce an effluent suitable for discharge.
2. Zero Liquid Discharge (ZLD) Concept, which consists of lime softening, followed by evaporation and crystallization to produce a solid salt for landfill disposal.
3. Discharge to a municipal sewage treatment facility or other receiving stream. This option is generally considered impractical, because the coal gasification wastewater exceeds typical pretreatment limitations.

Biological treatment of the gasification wastewater can be problematic, because the diverse contaminants are believed to be sufficiently variable so that the operation would be unreliable, which could result in violations of expected permit requirements. The open discharge system would cost approximately the same as the ZLD option and is not a proven technology in this application. The operating costs are equivalent between ZLD and open discharge systems. However, ZLD requires additional LP steam, which could otherwise be used to generate an additional 2 to 5 MW of electricity.

4.9 Acid Gas Removal Technology

Sulfur in coal is converted to H_2S and COS during gasification. The molar ratio of H_2S to COS in the raw syngas from the gasifier varies according to the gasifier type, from approximately 13 to 1 for the Shell gasifier to approximately 26 to 1 for the COP and GE gasifiers. The resulting syngas is treated to meet combustion turbine fuel and air emissions permit requirements. The requirement is for total sulfur in the clean syngas to be less than 25 ppm by weight, which is equivalent to 15 ppm by mole of COS and H_2S.

The two primary solvents considered for IGCC AGR are Selexol and methyl diethanol amine (MDEA). Selexol solvent is a mixture of dimethyl ethers of

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polyethylene glycol, $CH_3(CH_2CH_2O)_{(3\ to\ 9)}CH_3$. UOP licenses Selexol technology for treating syngas from gasification. Selexol is a physical solvent. Its capacity to absorb sulfur compounds (including H_2S) and to absorb CO_2 increases with increasing pressure and decreasing temperature.

MDEA, $(HOC_2H_4)2NCH_3$, is a chemical solvent, specifically a selective amine used to remove H_2S, while leaving most of the CO_2 in the syngas. MDEA forms a chemical bond with H_2S and CO_2. MDEA's performance is nearly independent of operating pressure. Typical absorber operating temperatures with amines are between 80 and 120° F. Lower absorber operating temperatures increase both H_2S solubility and selectivity over CO_2.

The higher absorber operating pressures and higher syngas CO_2 concentrations for the COP and GE gasification processes favor the use of Selexol, while MDEA is generally favored for the Shell gasification process.

4.10 Pre-combustion Carbon Capture

In the conventional IGCC case, the gasification process produces a synthetic gas (syngas) composed primarily of a homogeneous mixture of CO and hydrogen. This fuel is provided to a combined cycle power plant, and the combustion process produces comparably the same amount of CO_2 as does a conventional coal plant.

However, by adding water-gas shift and CO_2 absorption steps, the gasification process can yield a gaseous fuel stream that is nearly carbon-free, and a CO_2-rich solvent from which CO_2 can be removed for separate sequestration or other industrial uses. The fuel stream, composed mostly of hydrogen, would be used directly as a fuel in an appropriately designed combined cycle plant.[8] The outcome is the generation of "low carbon" electric power from a low-cost fuel source.

An IGCC facility with carbon capture capability would consist of a gasification process that is closely integrated with a conventional combined cycle power plant. The base facility would consist of five major components:

- ASU
- Gasification plant
- Gas cleanup
- Water shift process
- Combined cycle power plant

[8] Hydrogen fueled CTGs are not currently commercially available.

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After particulate and acid gas removal, clean syngas is water shifted prior to combustion in the power block. The result is a gas stream composed almost entirely of hydrogen and CO_2. From that stream, up to 90 percent of the CO_2 is then removed through a stripping process by passing the gas through an absorption tower using a physical CO_2 solvent. Hydrogen can then be provided as a nearly carbon-free fuel to the CTGs. The CO_2 removed by the solvent is recovered, cooled, compressed, dried, and transported to a sequestration location.

The addition of a carbon capture process would have a significant impact on the output and heat rate of an IGCC facility. Significantly higher auxiliary loads are required for compression loads in the capture process, and thermal energy in the form of process steam is required to separate the CO_2 from the absorption solvent. Energy would also be required for captured CO_2 compression. These energy requirements would have an impact on the net plant output and net plant heat rate of the facility. In order to maintain project required net plant output, additional generation capacity would need to be installed to compensate for the increased auxiliary loads of the carbon capture process. The increase in gross plant generation would meet the carbon capture process energy requirements.

Figure 4-3 shows a pre-combustion CO_2 removal process for a typical IGCC plant.

The inclusion of carbon capture in IGCC has several significant advantages over other carbon capture options:

- The process takes place at relatively high pressures and prior to the dilution of CO_2-containing gas. With CTGs, the combustion process occurs in a very large mass of compressed air, which adds excess oxygen and large amounts of nitrogen to the flue gas. In contrast, the volume of high-pressure pre-combustion syngas flow from which CO_2 must be removed is less by two orders of magnitude than that required in the post-combustion treatment of CTG flue gas streams, significantly reducing equipment dimensions, capacities, and costs.
- CO_2 capture takes place at temperatures and pressures in which a "physical" solvent can be used, instead of the chemical solvent required in most post-combustion processes. CO_2 can be separated from physical solvents through a pressure reduction process that requires much less thermal energy than the post-combustion alternative.
- There are additional cycle efficiency benefits that may occur as more advanced CTGs are developed. At the present time, F Class technologies

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are expected to be the CTG technology developed for high hydrogen, carbon-free applications in the near term. G and H Class technologies, along with other alternative CTG cycles, offer opportunities for efficiency improvements. While none of these technologies is currently capable of burning high hydrogen fuels, industry requirements, driven by the need for carbon capture, may stimulate the required research and development to enable this application.

Pertinent technology considerations include the following:

- While IGCC plants are in operation using F Class technologies, CO_2 capture applications where the CTGs are burning virtually pure hydrogen do not exist. CTG combustion system development is required to burn hydrogen to fully support the IGCC-based carbon capture.
- There is currently a large-scale coal gasification plant with carbon capture in North Dakota in commercial operation. The Great Plains Synfuel Plant has been operating since 1983 and gasifies 16,000 tons per day of lignite to produce synthetic natural gas. CO_2 is captured as a required precursor to methanation and used for EOR. While this scale is comparable to an electric power plant, the Great Plains plant is not directly comparable to a power plant because of the additional processes that are carried out at Great Plains. This example is the most relevant commercial operating experience for this carbon capture process.

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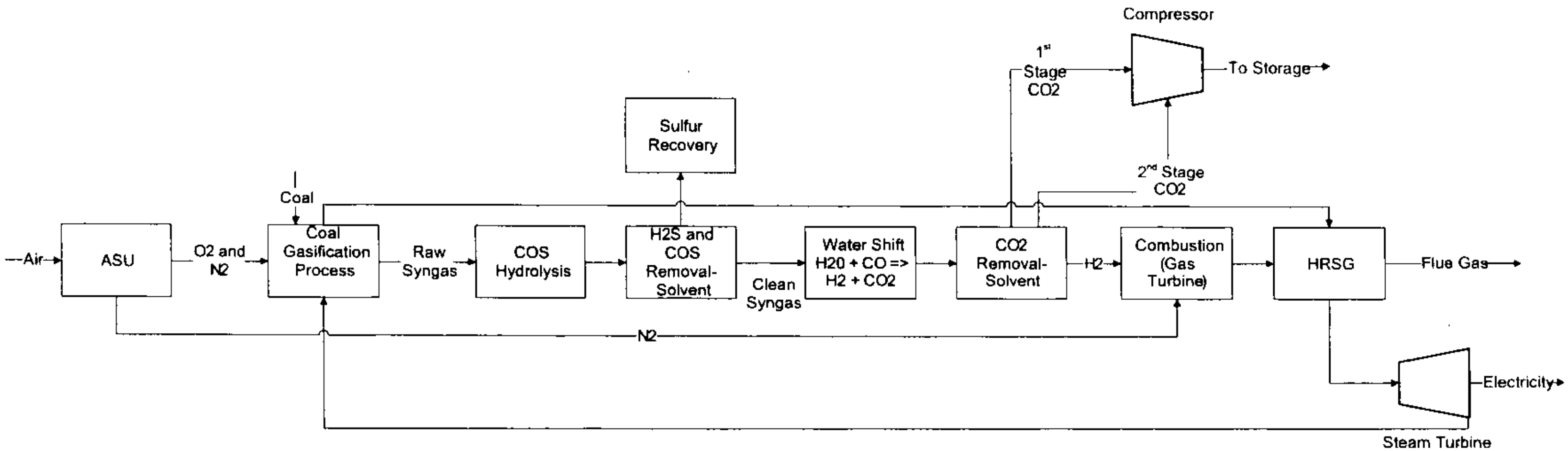

Figure 4-3. IGCC with Pre-Combustion CO_2 Capture.

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4.11 Equivalent Availability

An IGCC plant is not expected to be as reliable as a PC or CFB plant with respect to producing electricity from coal. IGCC plants without spare gasifiers are expected to achieve long-term annual equivalent availabilities in the 80 to 85 percent range versus approximately 90 percent for PC and CFB plants. Based on past experience, IGCC availability during initial startup and the first several years of operation is expected to be significantly lower than the long-term targets. This can be mitigated by firing the CTGs with backup fuel (such as natural gas or low sulfur fuel oil) however, this would reduce the fuel diversity benefit of adding coal fired generation. The equivalent availability of the combined cycle portion of an IGCC plant is expected to be above 90 percent. The equivalent availability of an IGCC plant can be increased by providing a spare gasifier. Spare gasifier economics depend on the gasifier technology, cost of backup fuel, and plant dispatch economics. The next generation of coal-fueled IGCC plants may take advantage of the lessons learned from existing operating plants, but significant startup problems should be expected.

4.11.1 First Generation IGCC Plants

Solids-related problems (erosion, pluggage, unstable flows, and syngas cooler tube leaks) caused significant gasification downtime for all four of the coal-based IGCC plants. Gasifier burner and refractory maintenance also resulted in significant downtime for the COP and GE gasifiers. For the Buggenum and Puertollano plants, CTG problems related to syngas combustion and startup air extraction were significant. Since the problems were identified, plant modifications and O&M improvements have greatly improved performance; these two plants now produce electricity at design rates and close to design efficiencies.

Estimated annual equivalent availabilities for producing electricity from coal (syngas operation) are listed in Table 4-5 for all four of the coal-based IGCC plants discussed in Section 4.5. These equivalent availabilities are for electricity production from coal or petcoke; power generation from firing the CTG on backup fuel is excluded. Gasification process availability for each of these plants was poor during the first several years of operation and continues to be a problem. The complexity and relative technological immaturity of large-scale commercial gasification processes increase opportunities for deficiencies in design, vendor-supplied equipment, construction, operation, and maintenance. During the first several years of plant operation, a number of these deficiencies were corrected, and the plant staff has optimized the plant O&M as they "move up the gasification learning curve." Design improvements are expected to be introduced on future IGCC plants, which should improve equivalent availability.

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4.11.2 Next (Second) Generation IGCC Plants

If the equivalent availability of the facility is critical to the project, the GE Quench technology with a spare gasifier is expected to provide high availability (from 85 to 90 percent), in the long term. However, as with all of the gasification technologies, in the first year, availability is expected to be around 50 percent. This would be expected to increase to the mature availability over four to five years.

Gasifiers with the water quench process have lower capital costs than gasifiers with HTHR. However, the GE Quench gasifiers have a lower efficiency power cycle because they produce LP steam instead of HP steam. Also, it is not practical to operate with a hot spare for gasifiers that use HTHR, because the HTHR requires a shutdown to switch gasifiers.

In the long-term IGCC unit forced outage rates are expected to range from 10 to 15 percent without a spare gasifier and from 5 to 10 percent with a hot spare gasifier. However, in the first year, the forced outage rate is expected to be around 45 percent. The CTG(s) can operate on backup fuel, if available, when syngas is not available. The combined cycle availability is expected to exceed 90 percent. Despite the comparatively low capital cost to add a spare Quench gasifier (roughly 60 percent of a HTHR gasifier), it appears that the prevailing sentiment in the gasification community is that the economics of a spare gasifier will be difficult to justify in most power generation applications, because of the reduced efficiency.

For many utilities, there is reduced power demand in the spring and/or fall of the year that would allow for annual planned outages. Because there are three gasifier/CTG trains, these would not typically be full plant outages, but would reduce the available output from the plant by one third for an extended time. Full plant planned outages would be required approximately every 6 years for steam turbine maintenance, similar to that required for a PC or CFB plant. The annual planned outages are a contributing factor to the lower expected equivalent availability of an IGCC plant as compared to a PC or CFB plant.

4.12 Other Commercial Entrained Bed Gasification Experience

GE Quench type gasifiers have been in commercial operation on coal or petcoke since 1983, producing syngas for chemical production. Two plants of note are the Eastman Chemical Plant in Kingsport, Tennessee, and the Ube Ammonia Plant in Japan. The syngas from these two plants is used to produce acetyl chemicals and ammonia, respectively. Kingsport has two gasifiers; one is normally operated and the other is a spare. Ube has four gasifiers; three are normally operated and one is a spare. Ube

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originally gasified crude oil, then switched to refinery residuals, then to coal, and has been gasifying a total of 1,650 tpd of petcoke since 1996. At Kingsport and Ube, an average syngas availability of 98 percent is achieved by rapid switchover to the spare gasifier, which is on hot standby, and the high level of resources (e.g., O&M) applied to the gasification process.

The Eastman Kingsport plant has occasionally been referred to as an IGCC plant. This is incorrect because it produces no power; the Eastman plant produces syngas for chemical production, with no power generation. The economics of chemical production at the Eastman facility are different from the economics of the power market. As such, a fully redundant gasifier is warranted at the Eastman facility. Eastman has made gasification one of its focus areas, as evidenced by its formation of the Eastman Gasification Services Company.

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Table 4-5. Coal/Coke-Fueled IGCC Plant Equivalent Availabilities

IGCC Plant Location	**Nuon** Buggenum Netherlands	**Global Energy** Wabash Indiana	**TECO** Polk County Florida	**Elcogas** Puertollano Spain
Gasifier	Shell	COP E-Gas	GE HTHR	Prenflo
Net Output	252 MW	262 MW	250 MW	300 MW
Startup Year	1994	1995	1996	1998
Year after Startup	**IGCC Equivalent Availability (percent)**			
1	23	20	35	16
2	29	43	67	38
3	50	60	60	59
4	60	40	75	62
5	61	70	69	66
6	60	69	74	58
7	57	75	68	NA
8	67	78	81	
9	73	--	82	
10	78	--		
11	NA			

Note:

1. Data is based upon available information. Data reporting methodology varies somewhat between the plants.
2. Wabash Years 5 to 8 IGCC equivalent availability estimated as 95 percent of reported syngas availability.
3. Wabash availability excludes periods when the plant was shut down because of no product demand (24 percent in Year 7 - 2002 and 16 percent in Year 8 – 2003, shutdown in Year 9 - 2004 and Year 10 - 2005).

4.13 Current Announced Electric Generation Industry Activity

Major industry participants, such as AEP and Duke Energy (formerly Cinergy), are considering implementing IGCC projects. In addition, numerous smaller companies are pursuing gasification projects using state and federal grants. The more advanced,

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publicly discussed IGCC projects of which Black & Veatch is aware are shown in the table below.[9]

Table 4-6. Announced IGCC Projects Currently In Development.

Owner	Size, MW	Fuel	Technology	Location
AEP	600	Bituminous	GE	OH
AEP	600	Bituminous	GE	WV
Duke/Cinergy	600	Bituminous	GE	IN
Excelsior	600	Bituminous/ PRB	COP	MN
Southern & OUC	285	PRB	KBR	FL
Global Energy	540	Petcoke	COP	IN
Global Energy	600	Petcoke	COP	OH
ERORA	557	Bituminous	GE	IL
Energy Northwest	600	PRB/Petcoke	NA	WA
NRG Northeast	630	PRB/Petcoke	Shell	CT
NRG Northeast	630	PRB/Petcoke	Shell	NY
TECO	789	Bituminous	GE	FL
Mississippi Power CO	700	Lignite	KBR	MS

4.13.1 Summary of Proposed Projects

The development activities of the eight companies discussed in the previous subsections represent advances in the development of new IGCC plants within the United States.

Entrained flow gasification technology has been selected by six of the companies. Southern Company and OUC are moving forward with the commercial demonstration of a transport bed gasifier. Energy Northwest has not selected a vendor at this stage, but all indications are that it will be a COP, GE, or Shell entrained flow gasification technology.

All of the projects are in coastal or Midwestern locations, with elevations generally at 1,000 feet or less.

The AEP, Duke, and ERORA projects are all based upon bituminous coal. The Global Energy Lima project is based upon petcoke. Excelsior Energy and Energy Northwest anticipate a blend of fuels that would include PRB coal with petcoke. The Southern Company/OUC project is based upon 100 percent PRB coal, but is a

[9] According to December 28, 2006, press release, AEP will delay its IGCC plant development to try to reduce the estimated capital cost to be within 20 percent of market pricing of "conventional coal fired power plant."

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commercial demonstration project for a new gasification technology and the demonstration will not be complete until 2015. The fuel supply for the NRG sites is primarily coal, but could include up to 20 percent petcoke and 5 percent biomass.

4.13.2 Gasification Market Opportunities

The gasification market appears to have strong opportunities in non-electric power generation sectors. Primarily, these are production of synthetic natural gas (SNG) and coal-to liquids (CTL). Gasification is also used worldwide for ammonia production from coal.

High natural gas prices have spurred interest in SNG production. Several such projects are currently in advanced stages of development. SNG has been proven commercially by the Great Plains facility in North Dakota which has been gasifying lignite for SNG production since 1983.

For the past several years, the continuous cost increase of petroleum based transportations fuels has created a market for alternative transportation fuels. This recently emerged market, coupled with the vast coal reserves of the US, provides potential near term gasification opportunities with CTL technologies. The US Departments of Defense and Energy both have technology development initiatives that are helping drive technology deployment in the US. CTL technologies are commercially available and proven.

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5.0 Performance and Emissions Estimates

Black & Veatch developed estimates of performance for four coal-fueled generation technology options. Both performance and emissions limits were developed for single units that would be installed at a multiple unit greenfield site. Project capacity has been specified as a nominal 2,000 MW net at the FGPP plant boundary. The project required net capacity would be met by installing blocks of power to obtain the nominal 2,000 MW.

The fuel used for the performance and cost estimates consisted of a blend of Central Appalachian coal, Colombian coal, and petcoke. The PC and CFB cases utilized a blend of 40 percent Central Appalachian coal, 40 percent Colombian coal, and 20 percent petcoke, referred to as the AQCS Blend.

Technical limitations exist that restrict the amount of petcoke that can be fired in PC units. These limitations are related to the fuel characteristics of petcoke. The low volatile matter of petcoke compared to its high fixed carbon content leads to flame instability in PC furnaces. In addition, the high sulfur content of petcoke, typically in the range of 3 to 8 percent, can lead to fireside corrosion of heat transfer equipment, flue gas path ductwork, and flue gas handling equipment. The high sulfur content also adds complications in meeting SO_2 emission requirements. Because of this, petcoke is typically co-fired with coal in PC units.

The IGCC case utilized a blend of 25 percent Central Appalachian coal, 25 percent Colombian coal, and 50 percent petcoke, referred to as the IGCC Blend.

For the purposes of this evaluation, the technologies were evaluated on a consistent basis relative to one another. The technologies, plant sizes, and arrangements that were considered for this study are shown in Table 2-1.

5.1 Assumptions

Black & Veatch and FPL developed assumptions for each of the technologies. The assumptions are provided in the following subsections.

5.1.1 Overall Assumptions

For the basis of the performance estimates, the site conditions of the proposed greenfield FGPP in Glades County, Moore Haven, Florida were used. The site conditions were provided to Black & Veatch by FPL. Performance estimates were developed for both the hot day and the average day ambient conditions. Following are the overall assumptions, which were consistent among all of the technologies:

- Elevation--20 feet.

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- Ambient barometric pressure--14.67 psia.
- Hot day ambient conditions:

  Dry-bulb temperature--95° F.

  Relative humidity--50 percent.
- Average day ambient conditions:

  Dry-bulb temperature--75° F.

  Relative Humidity--60 percent.
- The assumed fuel is a blend of three different fuel supplies. The ultimate analysis of these fuels, along with the analysis of the 40/40/20 and 25/25/50 blended fuels (which were used to determine performance and cost estimates for the PC, CFB, and advanced coal technologies, respectively) is provided in Table 5-1.
- AQCS were selected to develop performance and cost estimates, based on Black & Veatch experience. Actual AQCS would be selected to comply with federal NSPS and would be subject to a BACT review.

Table 5-1. Ultimate Fuel Analysis

Fuel	Appalachian Coal	Colombian Coal	Petcoke	AQCS Blend(1)	IGCC Blend(1)
Carbon, %	70.73	64.4	79	69.85	73.28
Sulfur, %	0.91	0.67	6.75	1.98	3.77
Oxygen, %	5.65	7.73	0.78	5.51	3.74
Hydrogen, %	4.62	4.6	3.3	4.35	3.96
Nitrogen, %	1.46	1.17	1.6	1.37	1.46
Chlorine, %	0.13	0.03	0.02	0.07	0.05
Ash, %	10.05	8.9	0.5	7.68	4.99
Water, %	6.45	12.5	8	9.18	8.74
HHV, Btu/lbm	12,510	11,300	13,676	12,300	12,800

(1)Developed from a blend of Appalachian coal, Colombian coal, and petcoke. Blended on the basis of percent weight.

5.1.2 Degradation of Performance

Net power plant output and heat rate performance for PC, CFB and IGCC plants can be expected to decline or "degrade" with hours of operation due to factors such as blade wear, erosion, corrosion, and increased tube leakage. The magnitude of

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performance degradation is dependent upon the specific characteristics of each facility such as mode of operation, fuel characteristics, water washing and maintenance practices as well as site specific ambient conditions. A portion of this degradation is recoverable and a portion is non-recoverable.

Periodic maintenance and overhauls can recover much, but not all, of the degraded performance compared to the unit's new and clean performance. The degradation which cannot be recovered is referred to as non-recoverable degradation. Performance that is recovered by scheduled maintenance is referred to as recoverable degradation. Performance degradation can also be reported as maximum degradation, which is the reduction in performance from clean and new equipment that is expected prior to a major overhaul.

Based on Black & Veatch experience, quantifying degradation in performance is difficult because actual data is not easily documented by the users and not easily obtained from the users or from the manufacturers. Many papers contain information regarding degradation in performance but the information is heavily qualified and vaguely presented thereby limiting analysis. For this study, a maximum degradation factor, a factor used to estimate the decline in a performance parameter, was assumed for each of the technologies. A maximum degradation of 1.0 percent for both the heat rate and net power output has been assumed for the PC and CFB cases. For the IGCC case, the maximum degradation was assumed to be 2.5 percent for both the heat rate and net power output.

5.1.3 PC and CFB Coal Cycle Arrangement Assumptions

The following assumptions were common to the SPC, USCPC, and CFB cases:

- All cases would utilize a wet mechanical draft cooling tower.
- A 40/40/20 fuel blend would be used for boiler efficiency in accordance with Table 5-1.
- Condenser performance was estimated on Black & Veatch experience. The expected condenser back pressures were supplied for hot and average day ambient conditions.
- The facilities would be designed for a nominal 2,000 MW net at the FGPP plant boundary by installing multiple units. Performance estimates were developed for multiple units generating a nominal 2,000 MW net of power at the average day ambient conditions.

The following subsections provide the specific assumptions used for each of the PC and CFB cases.

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5.1.3.1 *Subcritical PC.*

- Single unit capacity--500 MW net.
- Subcritical STG and subcritical PC boiler.
- Tandem-compound, four-flow, 33.5 inch last-stage blade (LSB) (TC4F-33.5) STG.
- Assumed capacity factor of 92.0 percent.
- AQCS:
    - LNB, overfire air (OFA), flue gas recirculation (FGR), and SCR for NOx control.
    - Wet limestone FGD for SO_2 control.
    - Activated Carbon Injection (ACI) for further Hg control
    - Pulse jet fabric filter (PJFF) for particulate control.
    - Wet electrostatic precipitator (ESP) for control of sulfuric acid mist (SAM.)
- Auxiliary power assumed to be 9.0 percent of gross plant output.
- The auxiliary load estimate was based on using motor driven boiler feed pumps (BFPs). This estimate would decrease by 2 to 3 percent if BFPs were turbine driven.
- Throttle conditions--2,415 psia, 1,050/1,050° F.
- Seven feedwater heaters (FWHs)--Three HP, three LP, and one deaerator (DA).
- Condenser pressure for hot and average day ambient conditions assumed to be 2.9 and 2.2 in. HgA, respectively.

5.1.3.2 *Ultrasupercritical PC.*

- Single unit capacity--1,000 MW net.
- Supercritical STG and supercritical PC boiler.
- TC4F-40.0 STG.
- Assumed capacity factor of 92.0 percent.
- AQCS:
    - LNB, OFA, FGR, and SCR for NOx control.
    - Wet limestone FGD for SO_2 control.
    - ACI for further Hg control
    - PJFF for particulate control.
    - Wet ESP for control of SAM.
- Auxiliary power assumed to be 7.0 percent of gross plant output.

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- The auxiliary load estimate was based on using turbine driven BFPs. This estimate would increase by 2 to 3 percent if BFPs were motor driven.
- Throttle conditions--3,715 psia, 1,112/1,130° F.
- Seven FWHs--Two HP, four LP, and one DA.
- Dual condenser used. For average ambient conditions, the HP condenser pressure was assumed to be 2.1 in. HgA; LP condenser pressure was assumed to be 1.7 in. HgA.

5.1.3.3 CFB.

- Single unit capacity--2x250 MW net boilers and 1x500 MW STG.
- Subcritical STG and subcritical CFB boiler.
- TC4F-33.5 STG.
- Assumed capacity factor of 88.0 percent.
- AQCS:
  - SNCR for NOx control.
  - Boiler limestone injection and wet limestone FGD for SO_2 control.[10]
  - ACI for further Hg control
  - PJFF for particulate control.
- Auxiliary power assumed to be 10.0 percent of gross plant output.
- The auxiliary load estimate was based on using motor driven boiler feed pumps (BFPs). This estimate would decrease by 2 to 3 percent if BFPs were turbine driven.
- Throttle conditions--2,415 psia, 1,050/1,050° F.
- Seven FWHs--Two HP, four LP, and one DA.
- Condenser pressure for hot and average day ambient conditions assumed to be 2.9 and 2.2 in. HgA, respectively.

5.1.4 IGCC Cycle Arrangement Assumptions

IGCC application has different issues that need to be considered. Unlike PC and CFB units, an IGCC cannot be sized to match a selected net plant output. The constraints are similar to that of a conventional natural gas fired simple or combined cycle unit. CTGs come in discrete sizes and are much more sensitive to changes in elevation and ambient temperature than thermal plants.

Currently, the most economic IGCC configurations are based upon state-of-the-art conventional "F" class CTGs modified to fire syngas. The GE 7FB and the Siemens SPG

[10] Wet FGD was applied to the CFB case to attain a comparable SO_2 emission to allow comparison with the PC options.

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SGT6-5000F CTGs are the most likely models to be incorporated in an IGCC plant. At International Organization for Standardization (ISO) conditions (sea level, 59° F, 60 percent relative humidity), these CTGS are rated at 232 MW when firing syngas. A single 7FB or SGT6-5000F in an IGCC configuration produces a nominal 300 MW net at ISO conditions. Therefore, a 3-on-1 IGCC configuration would produce a nominal 900 MW net at ISO conditions. The net output will vary somewhat depending upon the gasification technology employed, as well as the degree of integration.

The intent of the study was not to compare all of the gasification technologies against the PC and CFB options. To perform this study a gasifier technology choice needed to be made by Black & Veatch. Because of the fuel and location of the project, Black & Veatch selected GE Radiant as being representative of the commercial gasification technologies available. Based on experience, it was Black & Veatch's opinion that there would be not sufficient difference in cost and performance of one technology over another that would cause IGCC to be positively or negatively affected in the overall technology comparison. Black & Veatch did not select the GE Quench technology because GE currently prefers the Radiant in IGCC applications.

The following were assumed:

- Fuel supply used for gasifier feedstock in accordance with Table 5-1.
- Capacity factor of 80.0 percent.
- Six GE Radiant gasifiers.
- Six GE 7321(FB) CTGs with syngas combustors.
- TC2F-33.5 STG.
- Three-pressure reheat HRSG with duct firing.
- AQCS:
    - Selexol AGR.
    - Nitrogen diluent and syngas saturation for NO_x control.
    - Candle filter.
    - Sulfided carbon bed for Hg adsorption.
- 100 percent syngas fuel -- no backup fuel will be provided.
- Inlet air evaporative cooling above 59° F.
- Wet deaerating condenser.
- Throttle conditions--1,565 psia/1,000° F/1,000° F.
- For this evaluation, the STG was designed for normal pressure at average day conditions during syngas operation.

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5.2 Performance Estimates

Full-load performance estimates for each of the PC and CFB cases are presented in Table 5-2. Full-load performance estimates for the IGCC cases are presented in Table 5-3. The IGCC case is presented in a separate table from the PC and CFB cases because IGCC has some unique performance parameters.

5.2.1 PC and CFB Cases

Full-load performance estimates were developed for each of the specific PC and CFB cases. A total of six performances cases were run (two for each technology), consisting of performance estimates for the hot day and average day ambient conditions. Each of the cases was evaluated on a consistent basis to show the effects of technology selection on project performance. The performance estimates were generated for single units that would be installed at a multiple unit greenfield site.

5.2.2 IGCC Cases

Full-load performance estimates were developed for the IGCC cases. A total of two performance cases were run, one at hot day and one at average day ambient conditions. The IGCC case was evaluated on a consistent basis with the PC and CFB cases with respect to site and ambient conditions to show the effects of technology selection on project performance.

5.3 Emissions Estimates

For the purpose of estimating capital and O&M costs for AQCS, probable full-load emission limits were provided to Black & Veatch by FPL. These limits will be subject to later BACT review and are not intended to define performance requirements. Emissions estimates for the PC, CFB, and IGCC cases are summarized in Table 5-4. The emissions rates in the tables are expressed in lb/MBtu of heat input from the fuel. Emissions estimates should only be used for the screening-level evaluation. Final permit levels may vary on a case-by-case basis. Estimates of CO_2 emissions are shown in Table 5-5.

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Table 5-2. PC and CFB Coal Performance Estimates, per Unit

Technology Fuel	SPC AQCS Blend	USCPC AQCS Blend	CFB AQCS Blend
Performance on Average Ambient Day at 20 ft ASML, Clean and New Equipment			
Steam Conditions, psia/° F/° F	2,415/1,050/1,050	3,715/1,112/1,130	2,415/1,050/1,050
Fuel Input, MBtu/h	4,600	8,480	4,730
Boiler Efficiency (HHV), percent	88.9	88.9	87.0
Heat to Steam (HHV), MBtu/h	4,090	7,545	4,200
Gross Single Unit Output, MW	550	1,054	556
Total Auxiliary Load, MW	50	74	59
Net Single Unit Output, MW	500	980	497
Gross Turbine Heat Rate, Btu/kWh	7,450	7,140	7,540
Condenser Pressure, in. HgA	2.2	2.1/1.7	2.2
NPHR (HHV), Btu/kWh	9,210	8,660	9,510
Net Plant Efficiency (HHV), percent	37.0	39.4	35.9
Performance on Hot Day at 20 ft ASML, Clean and New Equipment			
Net Single Unit Output, MW	494	976	491
NPHR (HHV), Btu/kWh	9,340	8,690	9,640
Performance On Average Ambient Day at 20 ft ASML, Maximum Degradation (1.0% heat rate and 1.0% net plant output)			
Net Single Unit Output, MW	495	970	492
NPHR (HHV), Btu/kWh	9,300	8,750	9,610

Note:
USCPC option has dual condensers, therefore both pressures are listed.
No margins are applied to performance estimates.

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Table 5-3. GE Radiant IGCC Performance Estimates, per Unit

Fuel	IGCC Blend
Combined Cycle Configuration	3 x 1 GE 7FB
Performance on Average Day at 20 ft ASML, Clean and New Equipment	
Coal to Gasifiers, MBtu/h	8,400
Gasifier Cold Gas Efficiency (Clean Syngas HHV/Coal HHVx100)	74
CTG Heat Rate (LHV), Btu/kWh	8,370
CTG(s) Gross Power, MW	687
Steam Turbine Gross Power, MW	451
Syngas Expander Power, MW	5
Total Gross Power, MW	1,143
Aux. Power Consumption, MW	203
Net Power, MW	940
Net Plant Heat Rate (HHV), Btu/kWh	8,990
Net Plant Efficiency (HHV), Btu/kWh	38.0
Performance on Hot Day at 20 ft ASML, Clean and New Equipment	
Net Power, MW	902
Net Plant Heat Rate (HHV), Btu/kWh	9,360
Performance on Average Day at 20 ft ASML, Maximum Degradation (2.5% heat rate and 2.5% net power output)	
Net Power, MW	917
Net Plant Heat Rate (HHV), Btu/kWh	9,215

Notes:
Based on publicly available data from technology vendor.
No margins are applied to performance estimates.

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Table 5-4. Probable Air Emissions Limits				
Emissions	**SPC**	**USCPC**	**CFB**	**IGCC**
SO_2, lb/MBtu	0.04	0.04	0.04	0.015[a]
NO_x, lb/MBtu	0.05	0.05	0.07	0.06
PM_{10}, lb/MBtu, filterable	0.013	0.013	0.015	0.014
SAM, lb/MBtu	0.004	0.004	0.004	NA[b]
Hg, lb/MWh	9.9×10^{-6}	9.9×10^{-6}	10×10^{-6}	20×10^{-6}

Notes:

All emission limits are on a HHV basis.

[a] Probable emission limit under continuous operation. Normalized annual emission rate considering four start-ups and shutdowns could reach 0.038 lb/MBtu.[11]

[b] If SO_2 is properly controlled. H_2SO_4 emissions estimated at 5.6 lb/hr.

Table 5-5. Probable Air Emissions Limits				
Emissions	**SPC**	**USCPC**	**CFB**	**IGCC**
CO_2, lb/MBtu	208.1	208.1	208.1	209.8
CO_2, lb/MWh	1,935	1,821	1,989	1,933

Notes:

All emission limits are on a HHV basis.

Values are calculated based on fuel composition.

[11] Based on data presented in the Permit to Construct Application submitted on September 29, 2006, by AEP for the Mountaineer IGCC project.

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6.0 Cost Estimates

This section provides representative high-level cost estimates consisting of the following:

- Overnight capital cost estimates presented on an EPC basis exclusive of Owner's costs.
- O&M costs as fixed O&M costs and variable nonfuel O&M costs.

The cost estimates presented in this section were developed assuming that multiple units would be constructed at a single greenfield site. Multiple units will be constructed to obtain 2,000 MW of net nominal capacity at a single facility. Therefore, the cost estimates will be reflective of the economies of scale savings that occur for multiple unit facilities.

6.1 Capital Costs

Market-based overnight capital cost estimates for the four coal technologies were estimated. The estimates are expressed in 2006 US dollars and were developed using the assumptions listed in Section 5.1. An EPC cost basis was utilized exclusive of Owner's costs. Typically, the scope of work for EPC costs is the base plant, which is defined as being "within the fence" with distinct boundaries and terminal points. The values presented are believed to be reasonable for today's market. More importantly, the EPC costs were developed in a consistent manner and are reasonable relative to one another.

The cost estimate includes estimated costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis. The estimates were based on Black & Veatch proprietary estimating templates and experience. These estimates are screening-level estimates prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc., and as such are expected to be in the range of ±25 percent. The cost estimates were made using consistent methodology between technologies, so while the absolute cost estimates are expected to vary within a band of accuracy, the relative accuracy between technologies is better. The information is consistent with recent experience and market conditions, but as demonstrated in the last few years, the market is dynamic and unpredictable. Power plant costs will be subject to continued volatility in the future, and the estimates in this report should be considered primarily for comparative purposes. The AQCS for each technology were selected to meet the proposed emissions levels for criteria pollutants including NO_x, SO_2, Hg, and PM_{10}.

Given the level of uncertainty with developing screening-level capital costs, particularly for technologies with a limited database of actual installed costs, it is

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recommended that sensitivity evaluations be conducted to determine the competitiveness of a technology that appears cost-effective under base case assumptions.

6.2 Owner's Costs

The sum of the EPC capital cost and the Owner's cost equals the total project cost or the total capital requirement for the project. Typical Owner's costs that may apply are listed in Table 6-1. These costs are not usually included in the EPC estimate and should be considered by the project developer to determine the total capital requirement for the project. Owner's cost items include costs for "outside the fence" physical assets, project development, and financing costs. Interconnection costs can be major cost contributors to a project and should be evaluated in greater detail during the site selection. The order of magnitude of these costs is project-specific and can vary significantly, depending upon technology and project-unique requirements.

For a screening-level analysis, the Owner's cost, exclusive of interest during construction (IDC), can be estimated as a percentage of the EPC cost. Typically, based on actual project financial data, Owner's costs exclusive of IDC and escalation have been found to be in the range of 15 to 20 percent of the EPC cost for PC and CFB projects.

Additional considerations are merited for IGCC. Without a historical basis, Black & Veatch has added an allowance of 6 percent of the EPC cost. This contingency is in addition to the 15 to 20 percent Owner's costs, exclusive of IDC, and would cover the unexpected repairs and modifications needed during the initial years of operation. To attain high availability, it is assumed that the Owner would have to aggressively correct deficiencies and implement enhancements as they were identified. Some of the costs for correcting deficiencies can be recovered from the EPC contractor, but the Owner should expect to have significant initial operating costs that will not be reimbursed by the EPC contractor. Depending on the contracting arrangement and guarantees obtained, some of this responsibility/liability might be accepted by the EPC contractor, but it can be assumed that it would result in an equivalent price increase by the EPC contractor to assume the additional risk.

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Table 6-1. Potential Owner's Costs

Project Development:
- Site selection study
- Land purchase/options/rezoning
- Transmission/gas pipeline rights of way
- Road modifications/upgrades
- Demolition (if applicable)
- Environmental permitting/offsets
- Public relations/community development
- Legal assistance

Utility Interconnections:
- Natural gas service (if applicable)
- Gas system upgrades (if applicable)
- Electrical transmission
- Supply water
- Wastewater/sewer (if applicable)

Spare Parts and Plant Equipment:
- AQCS materials, supplies, and parts
- Acid gas treating materials, supplies, and parts
- Combustion and steam turbine materials, supplies, and parts
- HRSG, gasifier and/or boiler materials, supplies, and parts
- Balance-of-plant equipment/tools
- Rolling stock
- Plant furnishings and supplies

Owner's Project Management:
- Preparation of bid documents and selection of contractors and suppliers
- Provision of project management
- Performance of engineering due diligence
- Provision of personnel for site construction management

Plant Startup/Construction Support:
- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals/reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchase
- Construction all-risk insurance
- Acceptance testing
- Supply of trained operators to support equipment testing and commissioning

Taxes/Advisory Fees/Legal:
- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - Power Purchase Agreement (PPA)
  - Interconnect agreements
  - Contracts--procurement and construction
  - Property transfer

Owner's Contingency:
- Owner's uncertainty and costs pending final negotiation:
  - Unidentified project scope increases
  - Unidentified project requirements
  - Costs pending final agreement (e.g., interconnection contract costs)

Financing:
- Financial advisor, lender's legal, market analyst, and engineer
- Development of financing sufficient to meet project obligations or obtaining alternate sources of lending
- Interest during construction
- Loan administration and commitment fees
- Debt service reserve fund

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6.3 Nonfuel O&M Costs

Preliminary estimates of O&M expenses for the technologies of interest were developed. The O&M estimates were derived from other detailed estimates developed by Black & Veatch and are based on vendor estimates and recommendations, actual performance information gathered from in-service units, and representative costs for staffing, materials, and supplies. Plant staffing was assumed to provide operating and routine maintenance. The estimated O&M costs were developed using the assumptions listed for each of the cases in Section 5.1. Additional assumptions specific to O&M cost development are as follows:

- 6 year cycle between major STG overhauls.
- 2 year cycle between major PC boiler overhaul.
- 1 year cycle between major CFB boiler overhaul.
- 1 year cycle between major IGCC gasification overhaul
- Average plant technician salary would be $62,900/year, plus a 40 percent burden rate.
- Staff supplies and material were estimated to be 10 percent of staff salary.
- Insurance and property taxes are not included.
- Estimated employee training cost and incentive pay/bonuses are included.
- The variable O&M analysis was based on a repeating maintenance schedule for the boiler and STG and considers replacement and refurbishment costs.
- The fixed O&M analysis assumes that the fixed costs would remain constant over the life of the plant.
- Costs of major consumables are listed in Table 6-2.

Table 6-2. O&M Consumable Assumptions, $2006

Waste Disposal Cost	$/ton	6
Limestone Cost	$/ton	15
Lime Cost	$/ton	60
Ammonia Cost	$/ton	300
Urea Cost	$/ton	315
SCR Catalyst Cost	$/m^3	5,400
Powder Activated Carbon	$/lb	0.50

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6.4 Economies of Scale

6.4.1 Multiple Unit Sites

The benefit of economies of scale can be realized through facilities with high output and/or through multiple unit facilities. This assumes that the multiple units are duplicates of each other.

In most cases, a coal plant is initially designed for multiple units. Usually, the design calls for a minimum of two identical units, but can include three or four units. Capital intensive projects, such as PC units, realize substantial savings when the site includes multiple units. The savings will vary depending on the number of units installed at the site and the degree of interconnections and commonality of supporting systems.

The cost of the first unit on a two-unit site will be slightly higher than the cost for a single-unit site. This is because of the increased capacity of common systems or level of equipment redundancy and increased infrastructure. The increase in first-unit cost is expected to be in the range of 6 to 8 percent.

For a two-unit site, assuming identical units constructed within 1 to 2 years of each other, the second unit cost will be in the range of 75 to 80 percent of the first unit. A four-unit facility would typically be designed as two, two-unit plants. These economies of scale factors apply to EPC cost estimates that are exclusive of Owner's costs. The initial design of the plant should consider the economies of scale based on multiple units and/or unit size. The use of multiple identical units constructed in reasonable sequence will result in the greatest savings.

6.4.2 Economies of Scale Based on Unit Size

The cost per unit of output ($/kW) decreases as the output of the unit increases. This is mainly because there are many items (of cost) that are independent (in varying degrees) of unit size. Some examples include engineering for project design and manufacturing, manufacturing and construction management, distributed control system (DCS), instrumentation, plant infrastructure, project development cost, etc. Other independent costs, such as the Owner's costs (which were not estimated in this study), make the economies of scale based on unit size more significant.

6.5 Recent Experience

The estimated EPC costs were reviewed and adjusted according to recent conceptual-level cost estimates and Black & Veatch experience on actual projects. Black & Veatch has experienced substantial increases in costs over the past year. As an example, Black & Veatch had a experience with a boiler original equipment manufacturer (OEM) who increased a boiler quotation by about 20 percent. Additionally,

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it should be noted that AQCS prices have been increasing dramatically, and all AQCS OEMs are experiencing increased business. Costs continue to rise because of labor and material cost increases as well as market demand. For the present, the market has shifted to a seller's market. These cost increases apply to all of the technologies considered in this report.

6.6 Preliminary Cost Estimates

Preliminary capital cost estimates for the PC, CFB, and IGCC cases are presented in Table 6-3. These cost estimates were developed on an EPC basis and do not include Owner's costs. Nonfuel O&M cost estimates, including fixed costs and variable costs, are shown in Table 6-4. Both the capital and O&M costs estimates for the PC and CFB cases were developed on the basis of a multiple unit facility, so as to obtain nominal 2,000 MW of electrical power generation at a single facility.

Table 6-3. Capital Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
EPC Cost, 2006$MM	3,078	2,646	3,240	3,541
Unit EPC Cost, 2006$/kW	**1,540**	**1,350**	**1,630**	**1,880**
Escalation to 2012$	490	421	516	564
Subtotal - EPC Cost 2012$	*3,568*	*3,067*	*3,756*	*4,105*
Owner's Costs, 2012$	1,218	1,153	1,236	1,411
IDC, 2012$	1,063	914	1,119	1,223
Project Cost, 2012$	*5,849*	*5,134*	*6,111*	*6,739*
Unit EPC Cost, 2012$/kW	**2,925**	**2,619**	**3,074**	**3,585**

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Table 6-4. O&M Cost Estimates				
Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
Capacity Factor, percent	92.0	92.0	88.0	80.0
Annual Generation, GWh	16,100	15,800	15,300	13,200
Fixed Costs, 2006$, (1,000s)	35,780	27,500	38,800	47,810
Fixed Costs, 2006$/kW	17.89	14.03	19.54	25.43
Variable Costs, 2006$ (1,000s)	45,130	47,500	68,000	80,120
Variable Costs, 2006$/MWh	2.94	2.86	4.44	6.07
Fixed Costs, 2012$, (1,000s)	41,480	31,870	45,050	55,420
Fixed Costs, 2012$/kW	20.74	16.26	22.66	29.48
Variable Costs, 2012$ (1,000s)	54,900	52,300	78,600	92,930
Variable Costs, 2012$/MWh	3.41	3.31	5.14	7.04

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7.0 Economic Analysis

A busbar analysis was developed to compare the four technologies. The economic criteria, summary of inputs, and results are presented in this section.

7.1 Economic Criteria

The economic criteria utilized for the busbar analysis are summarized in Table 7-1. Estimated forecasts for the delivered price of the AQCS and IGCC fuel blends to the proposed FGPP throughout the life of the project were provided by FPL and are shown in Table 7-2.

Table 7-1. Economic Criteria

Parameter	
Owner's IGCC Risk Contingency, Percent of EPC Cost, percent	6.0
General Inflation, percent	3.0
Present Worth Discount Rate, percent	8.82
Levelized Fixed Charge Rate, percent	N/A [1]
First year CO_2 Allowance Credit - Mild, \$/ton 2012 [2]	7
First year CO_2 Allowance Credit - Stringent, \$/ton 2012 [3]	14
First year NO_x Allowance Credit, \$/ton 2012 [3]	1,676
First year SO_2 Allowance Credit, \$/ton 2012 [3]	1,399
First year Hg Allowance Credit, \$/lb 2012 [3]	25,459

Note:
[1] LFCR is not used in the economic analysis. Instead, an annual revenue requirement provided by FPL is applied to capital expenditures.
[2] From 4 pollutant 2005 Bingaman Proposal – Escalated at 2.5 percent after forecast period.
[3] From 4 pollutant 2005 McCain Proposal – Escalated at 2.5 percent after forecast period.
[4] From 3 pollutant proposal – Escalated at 2.5 percent after forecast period.

The busbar costs were calculated starting in 2012 and extending over the previously described economic durations. The busbar costs are presented in 2012$ assuming escalation of annual costs over the life of the project.

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Table 7-2. Fuel Forecasts ($/MBtu, delivered)		
Year	AQCS Blend(1)	IGCC Blend(1)
2012	2.90	2.68
2013	2.97	2.76
2014	3.04	2.83
2015	3.10	2.89
2016	3.17	2.95
2017	3.25	3.01
2018	3.32	3.07
2019	3.40	3.14
2020	3.49	3.21
2021	3.57	3.29
2022	3.66	3.36
2023	3.76	3.45
2024	3.85	3.53
2025	3.95	3.62
2026	4.04	3.70
2027	4.14	3.80
2028	4.24	3.89
2029	4.34	3.98
2030	4.45	4.08
2031	4.56	4.18
2032	4.68	4.29
2033	4.80	4.40
2034	4.92	4.51
2035	5.05	4.63
2036	5.19	4.75
2037	5.33	4.87
2038	5.49	5.02
2039	5.65	5.17
2040	5.82	5.33

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Table 7-2. Fuel Forecasts ($/MBtu, delivered)

Year	AQCS Blend[1]	IGCC Blend[1]
2041	6.00	5.49
2042	6.18	5.65
2043	6.36	5.82
2044	6.55	5.99
2045	6.75	6.17
2046	6.95	6.36
2047	7.16	6.55
2048	7.37	6.75
2049	7.60	6.95
2050	7.82	7.16
2051	8.06	7.37

[1] Developed from blends of Appalachian coal, Colombian coal, and petcoke. Blending calculated by %weight.

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7.2 Busbar Analysis

A levelized busbar cost analysis was performed using several sets of data. These include:

- Economic criteria provided by FPL, shown in Table 7-1.
- Fuel forecasts provided by FPL, shown in Table 7-2.
- Performance estimates for the PC, CFB, and IGCC cases listed in Table 5-2 and Table 5-3.
- EPC capital cost estimates listed in Table 6-3.
- O&M cost estimates listed in Table 6-4.

The PC and CFB cases were run with a 40 year book and 20 year tax life. The IGCC case was run with a 25 year book and 20 year tax life.

Performance was based on the annual average day conditions. The capacity factors for the PC, CFB, and IGCC units were assumed to be 92, 88, and 80 percent, respectively.

The IGCC analysis has not supplemented the capacity factor by assuming operation on natural gas to bring the capacity factor up to the same levels as the PC and CFB units. IGCC availability will be lower in the earlier years of operation as the operators learn how to run the plant and design modifications are made. The first year availability is expected to be around 50 percent. The base analysis has not reflected the ramp up from 50 to 80 percent in IGCC equivalent availability that is expected over the first five years of operation, and instead assumes that IGCC equivalent availability is 80 percent from the outset. This assumption is favorable for IGCC by overestimating annual generation.

A summary of the inputs consisting of estimates of performance and capital and O&M costs for each of the technologies used in the busbar analysis is provided in Table 7-3. Several cases were run:

- Degraded performance at average ambient conditions with no emissions allowance cost included.
- New and clean performance at average ambient conditions with no emissions allowance cost included.
- Degraded performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, and Hg. Emission allowance costs were estimated by multiplying a forecasted allowance cost by the total annual emissions of each pollutant based on the assumed control limits minus annual emission allocations for FGPP.
- New and clean performance at average ambient conditions with emissions allowance costs included for NO_x, SO_2, and Hg.

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- Degraded performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, Hg, and CO_2 using the Bingaman carbon tax estimate. No carbon capture was included.

Estimates of emissions allowance costs for NO_x, SO_2, Hg and the two CO_2 cases were taken from a report prepared by ICF International.[12] The costs are forecast through 2024. This study escalates the 2024 values by 2.5 percent annually through the last year of the economic analysis for each generation technology.

The results of the busbar analysis are provided in Table 7-4. From the analysis, the USCPC unit is the most cost effective technology. The analysis was run with the costs of emissions allowances included and excluded from the annual operating costs. In all instances, the USCPC is the most cost effective technology.

Table 7-3. Summary of Busbar Model Inputs

Technology	SPC	USCPC	CFB	IGCC
Cost Estimates				
EPC Capital Cost, 2006 $1,000	$3,078,000	$2,646,000	3,240,000	$3,541,000
Project Cost, Installed, 2012 $1,000	$5,850,000	$5,135,000	$6,111,000	$6,740,000
Fixed O&M, 2006 $/kW	17.89	14.03	19.54	$25.43
Variable O&M, 2006 $/MWh	2.94	2.86	4.44	$6.07
Fixed O&M, 2012 $/kW	20.74	16.26	22.66	$29.48
Variable O&M, 2012 $/MWh	3.41	3.33	5.14	$7.04
Average Day Performance				
New & Clean NPO, kW	2,000,000	1,960,000	1,988,000	1,880,000
Degraded NPO, kW	1,980,000	1,940,000	1,968,000	1,834,000
New & Clean NPHR, Btu/kWh (HHV)	9,210	8,660	9,510	8,990
Degraded NPHR, Btu/kWh (HHV)	9,300	8,750	9,610	9,215
Capacity Factor	92%	92%	88%	80%

[12] "U.S. Emission and Fuel Markets Outlook 2006," ICF International, Winter 2006/2007.

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Table 7-4. Busbar Cost Analysis Results, ¢/kWh

Case	SPC	USCPC	CFB	IGCC
Degraded performance, w/o emissions	9.56	8.63	10.54	12.69
New and clean performance, w/o emissions	9.47	8.54	10.43	12.38
Degraded performance, w/ emissions	9.68	8.74	10.66	12.81
New and clean performance, w/ emissions	9.58	8.65	10.56	12.50
Degraded performance, w/ emissions including CO_2	10.96	9.94	11.99	14.00

Note: Results were based on economic criteria from Table 7-1, fuel forecasts from Table 7-2, and the inputs from Table 7-3. These results are based on the maximum assumed capacity factors at average ambient conditions. Results are based on using 2012 cost estimates.

Three charts are provided to illustrate sensitivities of the busbar cost analysis. Figure 7-1 shows a breakdown of the components of the base case busbar cost without emissions allowances. It is seen that fuel and capital requirements make up the majority of the total busbar costs. Variations in these two cost categories will have the largest effect on the estimated busbar cost for any technology. Figures 7-2 and 7-3 are similar to Figure 7-1, but show the affect of adding the cost of emissions allowances. Figure 7-2 shows the incremental cost of adding allowance costs for NO_x, SO_2 and Hg. It can be seen that variations in emissions translate to minimal cost variations between the technologies. Figure 7-3 shows that the affect of adding CO_2 allowances (using the Bingaman case with no carbon capture). The carbon tax causes a noticeable increase to the absolute busbar costs, but because CO_2 emissions are relatively equal between technologies there is no effect on the rank order of busbar costs.

A sensitivity case was run that included potential costs of carbon capture. There have been many studies performed by other parties to quantify the cost of capturing carbon. Brief descriptions of available technologies were provided in Sections 3 and 4 of the report. Because study of the potential cost of carbon capture was not a focus of this effort, high level assessments have been made to provide a representation of the cost of carbon capture and show the relative effect of this added cost on the economic comparison between technologies.

A review of recent literature, including the US EPA "Environmental Footprints and Cost of Coal-Based Integrated Gasification and Pulverized Coal Technologies" and the Alstom chilled ammonia position paper indicates a probable range of carbon capture as shown in Table 7-5.

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Table 7-5. Probable Carbon Capture Costs, 2006$/Avoided Ton CO_2.		
Case	**Low Cost**	**High Cost**
Post-Combustion	20	40
Pre-Combustion	20	30

The cost range for pre-combustion is representative of current literature values published by technology neutral sources. The cost range for post-combustion uses Alstom's cost projection for their technology to establish the low value and then makes an assumption that the commercial cost could be 100 percent more for the high value. Estimated costs for other post combustion carbon capture systems published in other studies are higher than those published for this unique Alstom technology.

When these costs are added to the busbar cost analysis, with adjustments for output and net plant heat rate made as needed, the percentage increase of busbar cost over the base case analysis for new & clean conditions are as shown in Table 7-6.

Table 7-6. Probable Busbar Percentage Cost Increase with Carbon Capture and Emissions Allowances.		
Case	**Low Cost**	**High Cost**
SPC	20	30
USCPC	20	30
CFB	20	30
IGCC	20	25
Note: Assumes 90 percent carbon capture for conditions at average ambient temperatures compared to case with no emissions allowance costs. Includes emissions allowances for NO_x, SO_2, Hg, and emitted CO_2 using the 2005 McCain cost proposal.		

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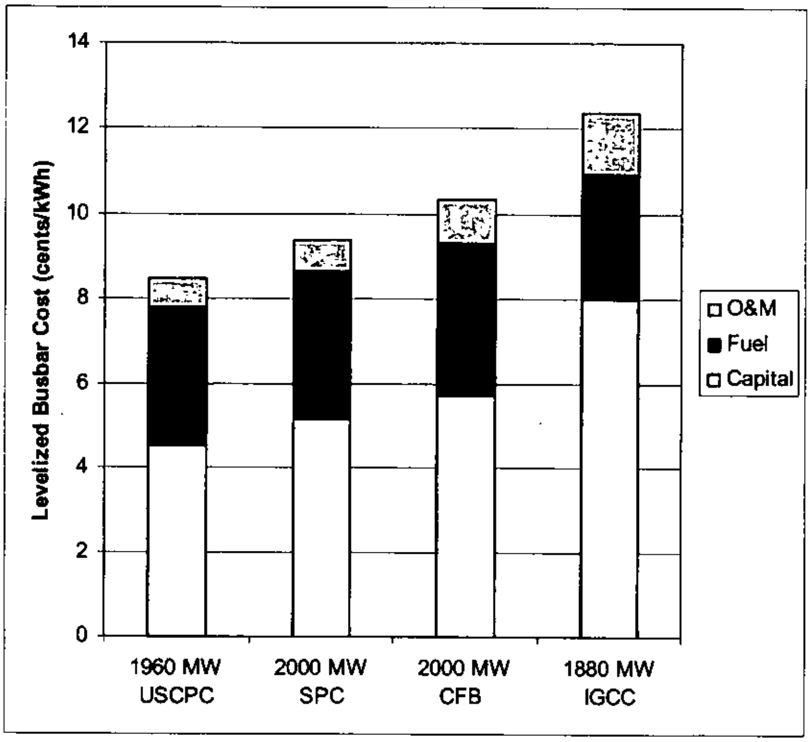

Figure 7-1. Busbar Cost Component Analysis without Emissions

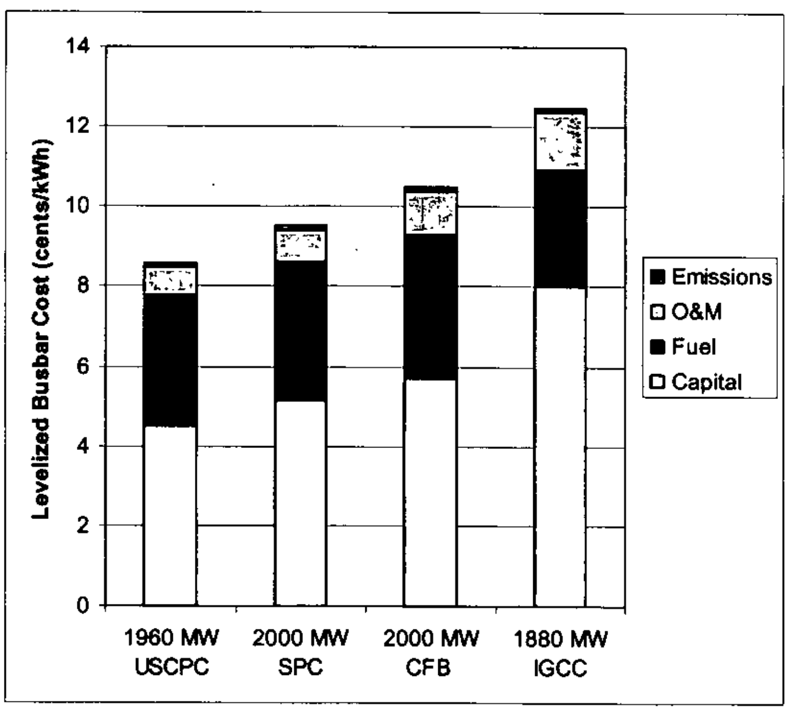

Figure 7-2. Busbar Cost Component Analysis with Emissions

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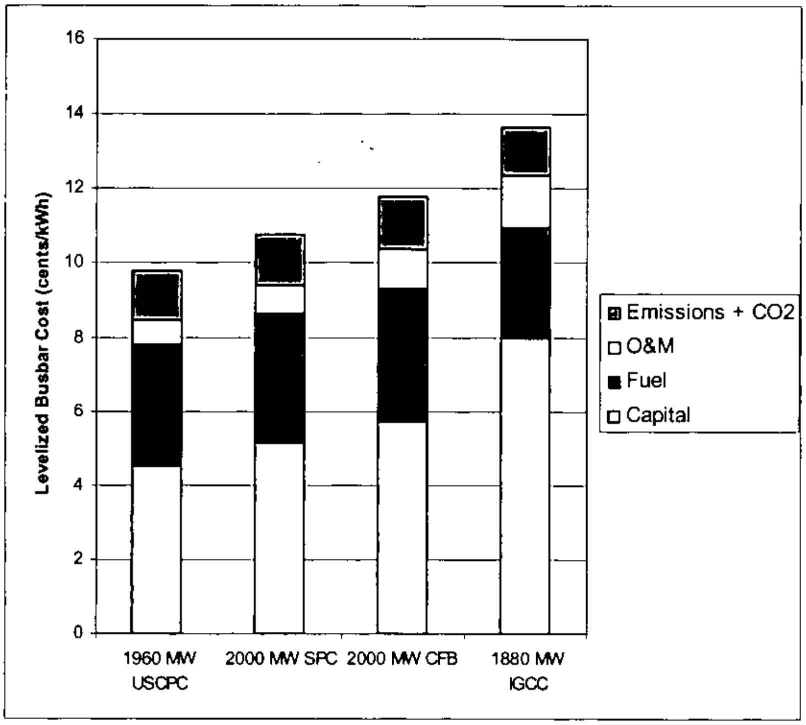

Figure 7-3. Busbar Cost Component Analysis with CO_2

A sensitivity analysis was run to show the effect variations in capacity factor have on economic analysis outputs. Figures 7-4 and 7-5 show the variations in busbar cost in cents per unit of generation (¢/kWh) and net levelized annual cost in dollars per unit of net plant output ($/kW) versus annual capacity factor. The sensitivity analysis was run over a range of capacity factors, from 40 percent to the maximum for each technology. The net plant heat rate was kept constant for all capacity factors, assuming full load operation. It can be seen that while all of the technologies have dramatic changes in busbar and net levelized annual cost across the range of capacity factors, the rank order of costs does not vary with capacity factor.

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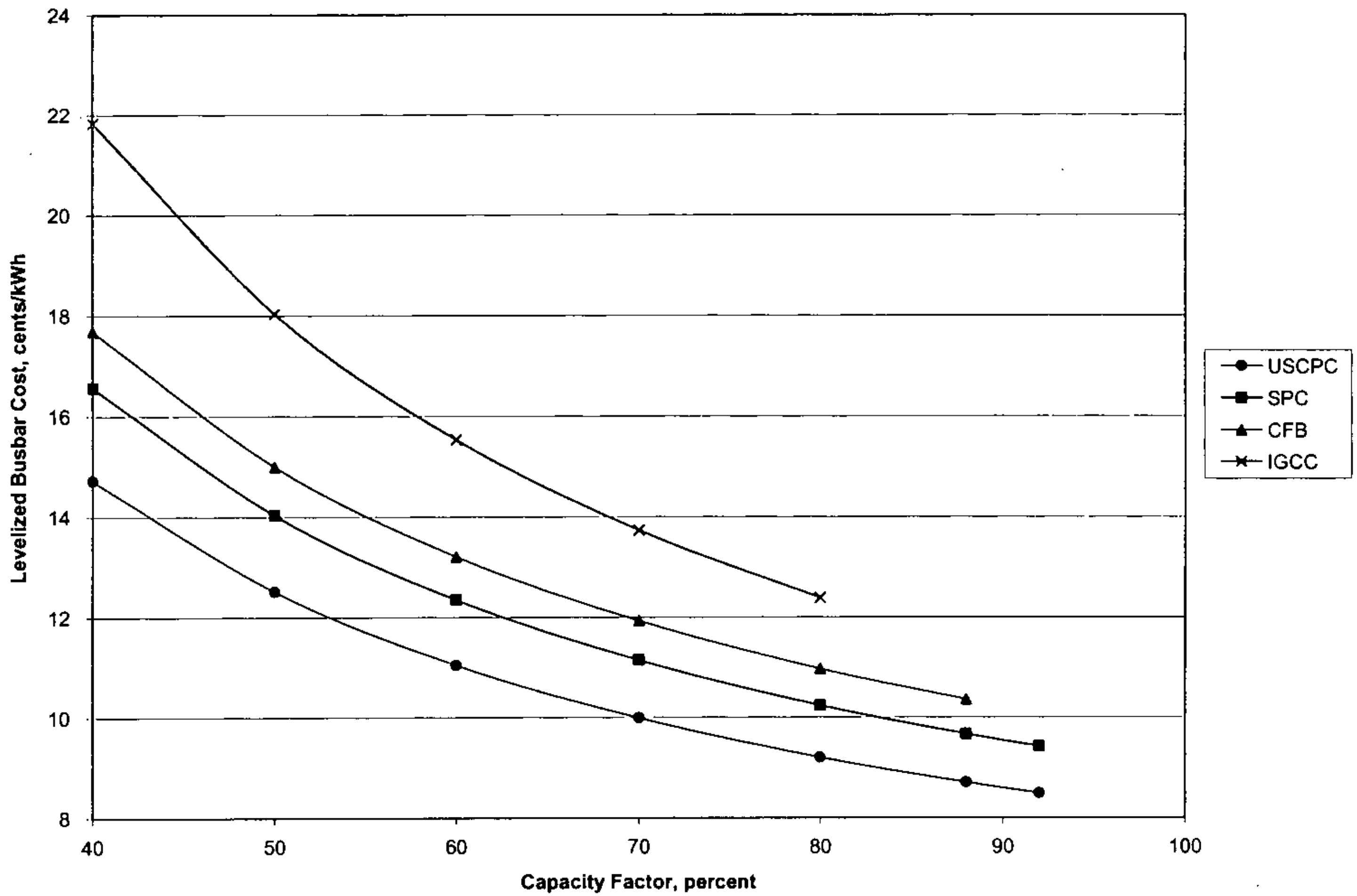

Figure 7-4. Busbar Cost Variation with Capacity Factor

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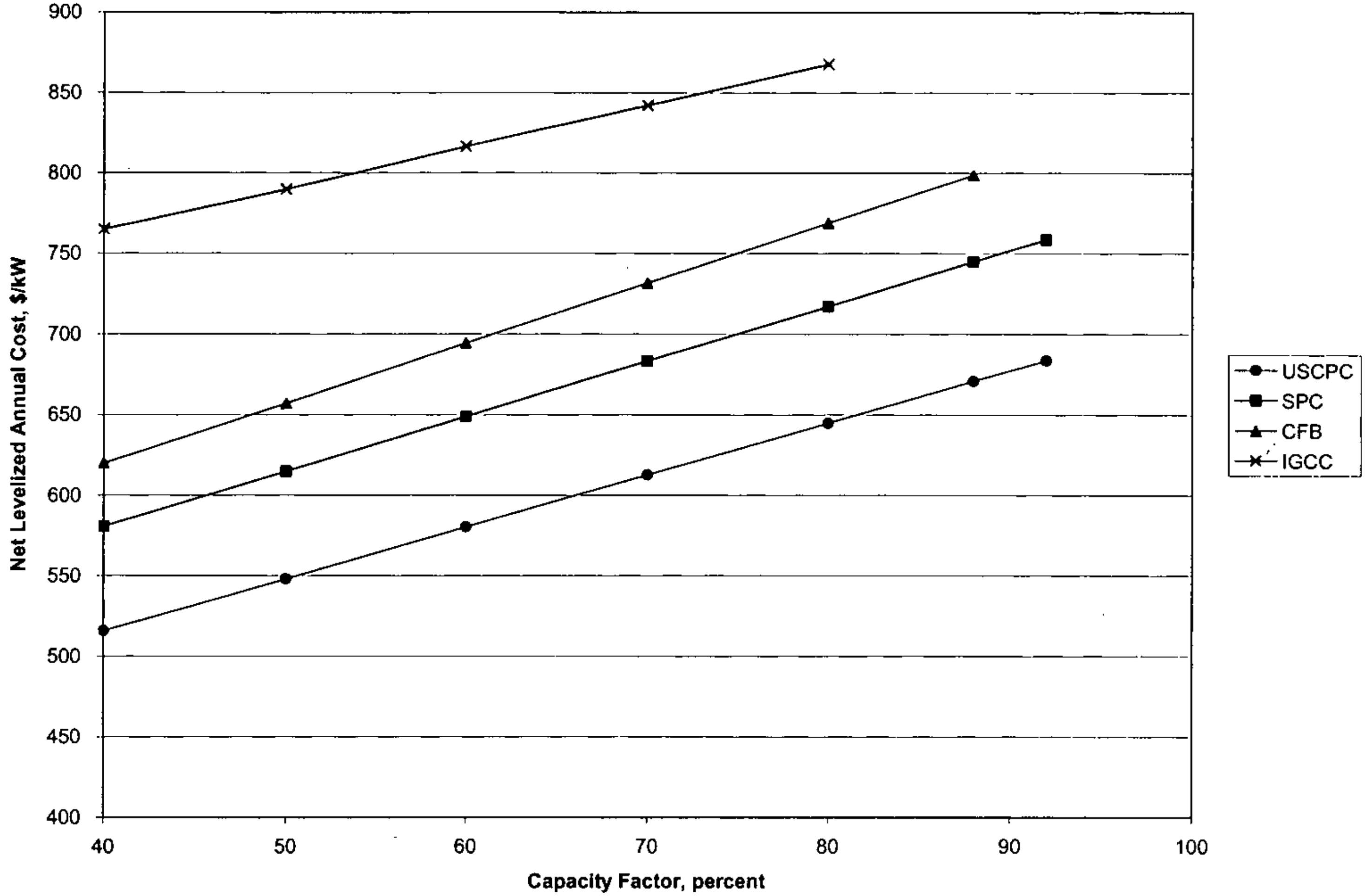

Figure 7-5. Net Levelized Annual Cost Variation with Capacity Factor

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8.0 Conclusions

This study made a comparison of performance and cost of four commercially available coal-fired power generation technologies. These were USPC, subcritical PC, CFB and IGCC. The estimates for performance were made using publicly available data and engineering data that has been collected by Black & Veatch and FPL. The results of the study are not intended to be absolute for any given technology but rather are intended to be accurate relative from one technology to another.

This study addresses technology risks known or assumed for each type of plant. Clearly PC plants are commercial and have been a dependable generation technology for years. The advancement of operation at ultrasupercritical steam conditions is somewhat new, but has been commercially demonstrated and proven around the world. CFB is also proven its dependability over the past two decades and is considered a mature technology. IGCC has been demonstrated on a commercial scale for over ten years. A second round of commercial scale IGCC plants is being planned currently. Many utilities will reserve decisions on making future IGCC installations until they have observed the installation and operation of these new plants.

Capital cost estimates for all power generation technologies are exhibiting considerable upward trends. Market pricing of technology components, coupled with commodity and labor demand worldwide, is rapidly escalating capital costs. These costs increases are not confined to any particular generation technology; they apply across the industry. The +/-25 percent accuracy range reflects the market volatility and the screening level nature of the estimate methodology.

Based on the assumptions, conditions, and engineering estimates made in this study, the USCPC option is the preferred technology selection for addition of a nominal 2,000 MW net output at the Glades site. The busbar cost of the USCPC case is nearly 10 percent less than SPC, which is the second lowest busbar cost case. USCPC will have good environmental performance because of its high efficiency. Emissions of NO_x and PM will be very similar across all technologies. Sulfur emissions would be slightly lower for IGCC than the PC and CFB options, although start-up and shutdown flaring will reduce the potential benefit of IGCC. The lower expected reliability of IGCC, particularly in the first years of operation, could compromise FPL's ability to meet the baseload generation requirement and require FPL to run existing units at higher capacity factors.

For the 2012-2014 planning time period, USCPC will be the best technical and economic choice for the installation of 2,000 MW of capacity at the Glades site.

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9.0 Contributors

This report was prepared collaboratively by Black & Veatch and FPL, as co-authors. Project team leads were David Hicks, Senior Director of Project Development, FPL, and Samuel Scupham, Technology Consultant, Black & Veatch Corporation. Messers Hicks and Scupham were supported in the preparation of this report by technical staff of their respective companies, to who they express their appreciation.

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ATTACHMENT FDEP-8

FGPP CONCENTRATION TABLES

TABLE FDEP-8a
SUMMARY OF MAXIMUM MEASURED O_3, SO_2, AND PM_{10} CONCENTRATIONS OBSERVED FROM REPRESENTATIVE MONITORING STATIONS, 2003 THROUGH 2005
FOR THE GLADES POWER PARK PROJECT

					Concentration									
			Measurement Period		1-Hour		3-Hour		8-Hour		8-Hour	24-Hour		Annual
AIRS No.	County	Location	Year	Months	Highest	2nd Highest	Highest	2nd Highest	Highest	2nd Highest	3-year Average 4th Highest	Highest	2nd Highest	Average
Ozone [a]		**Florida AAQS**			**NA**	**0.12 ppm**	**NA**	**NA**	**NA**	**NA**	**0.08 ppm**	**NA**	**NA**	**NA**
12-055-0003	Highlands	Sebring, 123 Main Drive	2005	Jan-Dec	0.079	0.079	NA	NA	NA	NA	0.072	NA	NA	NA
			2004	Jan-Dec	0.083	0.076	NA	NA	NA	NA	0.069	NA	NA	NA
			2003	Jan-Dec	0.093	0.084	NA	NA	NA	NA	NA	NA	NA	NA
12-099-0009	Palm Beach	Royal Palm B., 980 Crestwood Blvd.	2005	Jan-Dec	0.080	0.079	NA	NA	NA	NA	0.066	NA	NA	NA
			2004	Jan-Dec	0.080	0.077	NA	NA	NA	NA	0.066	NA	NA	NA
			2003	Jan-Dec	0.081	0.078	NA	NA	NA	NA	0.067	NA	NA	NA
12-071-3002	Lee	Ft. Myers Beach, School & Bay	2005	Jan-Dec	0.087	0.077	NA	NA	NA	NA	0.072	NA	NA	NA
			2004	Jan-Dec	0.087	0.087	NA	NA	NA	NA	0.070	NA	NA	NA
			2003	Jan-Dec	0.101	0.083	NA	NA	NA	NA	0.068	NA	NA	NA
Sulfur dioxide		**Florida AAQS**			**NA**	**NA**	**NA**	**0.5 ppm**	**0.5 ppm**	**0.5 ppm**	**NA**	**NA**	**0.1 ppm**	**0.02 ppm**
12-099-3004	Palm Beach	Riviera Beach, 1050 15th St. W	2005	Jan-Dec	NA	NA	0.003	0.003	0.003	0.003	NA	0.003	0.003	0.0012
			2004	Jan-Dec	NA	NA	0.002	0.002	0.002	0.002	NA	0.001	0.001	0.001
			2003	Jan-Dec	NA	NA	0.004	0.003	0.003	0.003	NA	0.002	0.002	0.001
12-115-1006	Sarasota	Sarasota, 4570 17th South	2005	Jan-Dec	NA	NA	0.024	0.015	0.015	0.015	NA	0.010	0.007	0.0013
			2004	Jan-Dec	NA	NA	0.014	0.014	0.014	0.014	NA	0.005	0.004	0.0012
			2003	Jan-Dec	NA	NA	0.026	0.024	0.024	0.024	NA	0.010	0.009	0.0016
PM_{10}		**Florida AAQS**			**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**150 μg/m³**	**50 μg/m³**
12-099-0008	Palm Beach	Belle Glade, 38754 State Road 80	2005	Jan-Dec	NA	NA	NA	NA	NA	NA	NA	41	38	17.6
			2004	Jan-Dec	NA	NA	NA	NA	NA	NA	NA	31	30	17.1
			2003	Jan-Dec	NA	NA	NA	NA	NA	NA	NA	30	28	16.4

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] On July 18, 1997, EPA promulgated revised AAQS for O_3. The O_3 standard was modified to be 0.08 ppm for the 8-hour average; achieved when the 3-year average of 98th percentile value is 0.08 ppm or less.

Source: EPA Air Quality System, Quick Look Reports, Florida: 2003, 2004, and 2005.

TABLE FDEP-8b
ILLUSTRATIVE 8-HOUR NO_2 AND O_3 CONCENTRATIONS FROM FGPP

Range (m)		2001		2002		2003		2004		2005	
lower	upper	Max	Avg.	Max	Avg.	Max	Avg.	Max	Avg.	Max	Avg.
8-Hour Average NO_2 Concentration (ug/m^3)											
1000	2000	6.22	4.53	6.21	4.73	6.16	4.52	6.91	4.55	7.29	5.04
2000	3000	5.44	3.70	6.26	3.96	5.48	3.79	6.27	4.11	6.48	4.04
3000	4000	4.21	2.79	4.40	2.92	4.15	2.85	4.86	3.23	4.18	3.04
4000	5000	3.23	2.17	3.64	2.35	3.35	2.32	4.78	2.46	3.99	2.40
5000	7500	2.82	1.75	3.61	1.88	2.87	1.82	4.63	2.03	3.90	1.91
7500	10000	2.32	1.46	3.16	1.46	2.31	1.44	3.83	1.63	3.30	1.54
10000	15000	1.75	1.26	2.73	1.22	2.17	1.21	3.18	1.46	2.62	1.25
8-Hour Average O_3 Concentration (ug/m^3)											
1000	2000	6.49	4.72	6.48	4.94	6.43	4.72	7.21	4.75	7.61	5.26
2000	3000	5.68	3.86	6.53	4.13	5.72	3.95	6.54	4.29	6.76	4.21
3000	4000	4.40	2.91	4.59	3.05	4.33	2.97	5.07	3.37	4.36	3.17
4000	5000	3.37	2.26	3.80	2.45	3.50	2.42	4.99	2.56	4.17	2.50
5000	7500	2.94	1.82	3.77	1.96	2.99	1.90	4.83	2.12	4.07	1.99
7500	10000	2.42	1.53	3.29	1.53	2.41	1.50	3.99	1.71	3.45	1.61
10000	15000	1.83	1.32	2.85	1.27	2.27	1.26	3.32	1.52	2.73	1.30

Note: 8-Hour Average O_3 Standard (ug/m3) = 157 ug/m^3.

ATTACHMENT FDEP-10

COMPARISON OF PERFORMANCE AND EMISSIONS OF FGPP AND DESERT ROCK ENERGY CENTER

TABLE FDEP-10
COMPARISON OF PERFORMANCE AND EMISSIONS OF FGPP AND DESERT ROCK ENERGY CENTER

Parameter	Units	FGPP	Desert Rock
Heat Input (per Unit)	MMBtu/hr	8,700	6,800
Capacity (gross)	MW	1,060	750
Heat Rate (gross)	Btu/kW-hr	8,208	9,067
Capacity (net)	MW	980	683
Heat Rate (net)	Btu/kW-hr	8,878	9,956
PM/PM_{10}	lb/MMBtu[a]	0.013	0.01
	lb/MW-hr (gross)	0.107	0.091
	lb/MW-hr (net)	0.115	0.100
NO_x	lb/MMBtu[b]	0.05	0.06
	lb/MW-hr (gross)	0.410	0.544
	lb/MW-hr (net)	0.444	0.597
SO_2	lb/MMBtu[b]	0.04	0.06
	lb/MW-hr (gross)	0.328	0.544
	lb/MW-hr (net)	0.355	0.597
CO	lb/MMBtu[a]	0.13	0.1
	lb/MW-hr (gross)	1.067	0.907
	lb/MW-hr (net)	1.154	0.996
VOC	lb/MMBtu[a]	0.0034	0.003
	lb/MW-hr (gross)	0.028	0.027
	lb/MW-hr (net)	0.030	0.030
SAM	lb/MMBtu[a]	0.004	0.004
	lb/MW-hr (gross)	0.033	0.036
	lb/MW-hr (net)	0.036	0.040
Fluorides	lb/MMBtu	0.00023	0.00024
	lb/MW-hr (gross)	0.0019	0.0022
	lb/MW-hr (net)	0.0020	0.0024
Mercury	$lb/10^{12}$ Btu	1.21	2.21
	10^{-6} lb/MW-hr (gross)[c]	9.9	20

[a] Stack test method (3-hour).

[b] 24-hour.

[c] Annual average. For CO FPL is proposing an emission limit of 0.13 lb/MMBtu as a 3-hour test for coal-only firing.

Sources: FGPP Air Costruction/PSD Application, 2006; EPA Region 9 Proposed Permit Conditions (AZP-04-01)
Desert Rock Energy Facility Application for PSD Permit - CLASS I Modeling Update, 2006.

ATTACHMENT FDEP-15

MERCURY EMISSIONS TABLES

TABLE H-15a
FLORIDA MERCURY EMISSION INVENTORY

Emission Report by Facility

Data for this Report is One Day Old Production Data.

Facility ID	Owner/Company Name	Site Name	City	Office	County	Status	SIC	Type	Pollutant	Actual(TPY) 2005	Actual(TPY) 2004
10006	CITY OF GAINESVILLE, GRU	DEERHAVEN GENERATING STATION	GAINESVILLE	NED	ALACHUA	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
10041	N. FLA/SOUTH GA VETERANS HEALTH SYSTEM	GAINESVILLE	GAINESVILLE	NED	ALACHUA	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0.0001	0.0001
10083	SAFT AEROSPACE BATTERIES***INACTIVE***	SAFT AEROSPACE BATTERIES	ALACHUA	NEDB	ALACHUA	INACTIVE	3691	LEAD ACID BATTERY PLANT	H114		
10087	FLORIDA ROCK INDUSTRIES, INC.	THOMPSON S. BAKER CEMENT PLANT	NEWBERRY	NED	ALACHUA	ACTIVE	3241	PORTLAND CEMENT PLANT	H114	0.024	0.0146
30010	HANSON ROOF TILE	SANDERSON FACILITY	SANDERSON	NED	BAKER	CONSTRUCTION	3259	CONCRETE PLANT	H114		
50031	BAY COUNTY BOARD OF COUNTY COMMISSIONERS	MONTENAY BAY, LLC	PANAMA CITY	NWDP	BAY	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.0467	0.0495
90008	ORLANDO UTLITIES COMMISSION	INDIAN RIVER PLANT - OUC	TITUSVILLE	CD	BREVARD	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
90051	NASA	NASA/KENNEDY SPACE CENTER	KENNEDY SPACE CENTER	CD	BREVARD	ACTIVE	9661	OTHER	H114	0.0001	0
90124	AERC.COM, INC	AERC COM,INC	WEST MELBOURNE	CD	BREVARD	ACTIVE	8999	PATHOLOGICAL INCINERATOR	H114	0	0
90196	RELIANT ENERGY FLORIDA, L.L.C.	RELIANT INDIAN RIVER PLANT	TITUSVILLE	CD	BREVARD	ACTIVE	4911	OTHER ELECTRIC PRODUCTION	H114		
110002	MEMORIAL REGIO HOSP/SO BROWARD HOSP DIST	MEMORIAL REGIO HOSP/SO BROWARD HOSP DIST	HOLLYWOOD	SEBR	BROWARD	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0	0
110037	FLORIDA POWER & LIGHT (PFL)	FT. LAUDERDALE POWER PLANT	FT. LAUDERDALE	SEBR	BROWARD	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0.0064	0.0056
111019	HOLY CROSS HOSPITAL	HOLY CROSS HOSPITAL	FORT LAUDERDALE	SEBR	BROWARD	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0	0
112119	WHEELABRATOR SOUTH BROWARD, INC	WHEELABRATOR SOUTH BROWARD	FT. LAUDERDALE	SED	BROWARD	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.1297	0.0635
112120	WHEELABRATOR NORTH BROWARD, INC.	WHEELABRATOR NORTH BROWARD	POMPANO BEACH	SED	BROWARD	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.0352	0.0425
210045	NAPLES COMMUNITY HOSPITAL	NAPLES COMMUNITY HOSPITAL	NAPLES FL	SD	COLLIER	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114		
230019	N. FLA/SOUTH GA VETERANS HEALTH SYSTEM	LAKE CITY	LAKE CITY	NED	COLUMBIA	INACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0	0
250014	RINKER MATERIALS CORPORATION.	MIAMI CEMENT PLANT	MIAMI	SEDA	MIAMI-DADE	ACTIVE	3241	PORTLAND CEMENT PLANT	H114	0.0039	0.0037
250020	TARMAC AMERICA LLC	TARMAC-PENNSUCO CEMENT	MEDLEY	SEDA	MIAMI-DADE	ACTIVE	3241	PORTLAND CEMENT PLANT	H114	0.08	0
250022	U S FOUNDRY MANUFACTURING CORP.	U S FOUNDRY MANUFACTURING CORP.	MEDLEY	SEDA	MIAMI-DADE	ACTIVE	3321	SECONDARY METAL PRODUCTION	H114		
250337	MERCY HOSPITAL	MERCY HOSPITAL	MIAMI	SEDA	MIAMI-DADE	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0	0

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250348	MIAMI DADE RRF	MIAMI DADE RRF/MONTENAY	MIAMI	SED	MIAMI-DADE	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.008	0.01
290016	DIXIE WASTE SERVICES LLC	DIXIE WASTE SERVICES GASIFICATION	CROSS CITY	NED	DIXIE	CONSTRUCTION			H114		
310001	JACKSONVILLE ELECTRIC AUTHORITY	ST JOHNS RIVER POWER PARK	JACKSONVILLE	NED	DUVAL	INACTIVE	4911	STEAM ELECTRIC PLANT	H114		
310003	JAX MARITIME PARTNERS, LLC	JACKSONVILLE MILL	JACKSONVILLE	NEDV	DUVAL	INACTIVE	2631	PULP & PAPER PLANT	H114		
310004	KRAFT FOODS GLOBAL, MAXWELL HOUSE COFFEE	KRAFT FOODS, MAXWELL HOUSE COFFEE	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2095	OTHER FOOD PRODUCTION	H114		
310005	ANCHOR GLASS CONTAINER CORPORATION	JACKSONVILLE PLANT 07	JACKSONVILLE	NEDV	DUVAL	ACTIVE	3221	GLASS CONTAINER PLANT	H114		
310006	ANHEUSER BUSCH, INC. JACKSONVILLE	ANHEUSER BUSCH, INC. JACKSONVILLE	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2082	OTHER FOOD PRODUCTION	H114		
310010	BAPTIST MEDICAL CENTER	BAPTIST MEDICAL CENTER	JACKSONVILLE	NEDV	DUVAL	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114		
310014	BACARDI BOTTLING CORPORATION	BACARDI BOTTLING CORPORATION	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2085	OTHER FOOD PRODUCTION	H114		
310025	ATLANTIC COAST ASPHALT	HECKSCHER ASPHALT PLANT	JACKSONVILLE	NEDV	DUVAL	INACTIVE	2951	ASPHALT PLANT	H114	0	0
310026	ATLANTIC COAST ASPHALT, INC.	SHAD ASPHALT PLANT	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2951	ASPHALT PLANT	H114	0.0004	0.0005
310028	SUPPORT TERMINAL OPERATING PART. L.P.	SUPPORT TERMINAL SERVICES, INC.	JACKSONVILLE	NEDV	DUVAL	ACTIVE	4226	PETROLEUM STORAGE/TRANSFER	H114		
310039	MILLENNIUM SPECIALTY CHEMICALS	JACKSONVILLE FACILITY	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2869 2844	OTHER CHEMICAL PLANT	H114		0
310043	DUVAL ASPHALT PRODUCTS	PHILLIPS HIGHWAY PLANT	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2951	ASPHALT PLANT	H114	0.0004	
310045	JEA	NORTHSIDE/SJRPP	JACKSONVILLE	NEDV	DUVAL	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0.0592	0.1772
310046	JEA	SOUTHSIDE	JACKSONVILLE	NEDV	DUVAL	INACTIVE	4911	STEAM ELECTRIC PLANT	H114		
310047	JEA	KENNEDY	JACKSONVILLE	NEDV	DUVAL	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
310050	OWENS-CORNING	OWENS-CORNING, JACKSONVILLE PLANT	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2952	FIBERGLASS PRODUCTS MFG.	H114	0	0
310067	SMURFIT-STONE CONTAINER ENTERPRISES, INC	D/B/A SMURFIT-STONE CONTAINER CORPORATIO	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2621	PULP & PAPER PLANT	H114	0	
310068	ST VINCENTS MEDICAL CENTER	ST VINCENTS MEDICAL CENTER	JACKSONVILLE	NEDV	DUVAL	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114		
310071	IFF CHEMICAL HOLDINGS, INC.	IFF CHEMICAL HOLDINGS, INC.	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2869	OTHER CHEMICAL PLANT	H114		

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310072	UNITED STATES GYPSUM CO.	JACKSONVILLE PLANT	JACKSONVILLE	NEDV	DUVAL	ACTIVE	3275	GYPSUM PRODUCTION	H114	0.0003	
310097	METAL CONTAINER CORPORATION	METAL CONTAINER CORPORATION	JACKSONVILLE	NEDV	DUVAL	ACTIVE	3411	SURFACE COATING OPERATION	H114	0	
310125	REICHHOLD, INC.	REICHHOLD, INC.	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2821	OTHER CHEMICAL PLANT	H114		
310146	SWISHER INTERNATIONAL, INC.	SWISHER INTERNATIONAL, INC.	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2121	OTHER	H114	0	
310157	GERDAU AMERISTEEL JACKSONVILLE MILL DIV.	GERDAU AMERISTEEL JACKSONVILLE MILL DIV.	BALDWIN	NEDV	DUVAL	ACTIVE	3312	STEAM ELECTRIC PLANT	H114		
310166	JEA	BUCKMAN ST. WASTEWATER TREATMENT PLANT	JACKSONVILLE	NEDV	DUVAL	ACTIVE	4952	OTHER INCINERATION	H114		
310180	HESS CORPORATION	HESS - JACKSONVILLE TERMINAL	JACKSONVILLE	NEDV	DUVAL	ACTIVE	5171	PETROLEUM STORAGE/TRANSFER	H114		
310183	ST LUKE'S HOSPITAL ASSOCIATION	ST LUKE'S HOSPITAL ASSOCIATION	JACKSONVILLE	NEDV	DUVAL	INACTIVE	8062	HOSPITALS/HEALTH CARE	H114		
310188	COASTAL TERMINALS LLC	JACKSONVILLE TERMINAL	JACKSONVILLE	NEDV	DUVAL	ACTIVE	5171	PETROLEUM STORAGE/TRANSFER	H114	0	
310202	BPB MANUFACTURING, INC	JACKSONVILLE PLANT	JACKSONVILLE	NEDV	DUVAL	ACTIVE	3275	GYPSUM PRODUCTION	H114		
310213	U S NAVAL STATION MAYPORT	MAYPORT	JACKSONVILLE	NEDV	DUVAL	ACTIVE	9711	OTHER	H114		
310215	UNITED STATES NAVY	NAS-JACKSONVILLE	JACKSONVILLE	NEDV	DUVAL	ACTIVE	9711	OTHER	H114		
310238	SMURFIT STONE CONTAINER ENTERPRISES, INC	DI-NA-CAL LABEL GROUP, JACKSONVILLE, FL	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2754	GRAPHICS ARTS/PRINTING	H114	0	
310258	ATLANTIC DRY DOCK, LLC	ATLANTIC DRY DOCK CORP/ATLANTIC MARINE	JACKSONVILLE	NEDV	DUVAL	ACTIVE	3731	ABRASIVE BLAST CLEANING	H114	0	
310271	GOODRICH CORPORATION	ENGINEERED POLYMER PRODUCTS	JACKSONVILLE	NEDV	DUVAL	ACTIVE	3069	OTHER	H114		0
310303	WINCUP	WINCUP	JACKSONVILLE	NEDV	DUVAL	ACTIVE	3086	OTHER CHEMICAL PLANT	H114		
310318	CITY OF JACKSONVILLE(GIRVIN RD LANDFILL)	E. DUVAL SANITARY LANDFILL	JACKSONVILLE	NEDV	DUVAL	ACTIVE	4953	MUNICIPAL SOLID WASTE LANDFILL	H114		
310326	INTERSTATE BRANDS CORPORATION	INTERSTATE BRANDS CORPORATION	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2051	OTHER FOOD PRODUCTION	H114		
310337	CEDAR BAY COGENERATION INC.	CEDAR BAY COGENERATION INC.	JACKSONVILLE	NEDV	DUVAL	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0.0146	0.0144
310356	SMURFIT-STONE CONTAINER ENTERPRISES	SMURFIT-STONE CONTAINER (JACKSONVILLE)	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2653	OTHER	H114		
310418	FLOWERS BAKERY	FLOWERS BAKERY	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2051	OTHER FOOD PRODUCTION	H114	0	0

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310485	JEA	BRANDY BRANCH FACILITY	BALDWIN CITY	NEDV	DUVAL	ACTIVE	4911	OTHER ELECTRIC PRODUCTION	H114		
310496	JET TURBINE SERVICE, INC (JTS)	NAS CECIL FIELD	JACKSONVILLE	NEDV	DUVAL	ACTIVE	9711	OTHER	H114	0	
330041	SACRED HEART HEALTH SYSTEM	SACRED HEART HOSPITAL	PENSACOLA	NWD	ESCAMBIA	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0	0
330045	GULF POWER COMPANY	CRIST ELECTRIC GENERATING PLANT	PENSACOLA	NWD	ESCAMBIA	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
330067	ESCAMBIA COUNTY UTILITIES AUTHORITY	MAIN STREET WWTP	PENSACOLA	NWD	ESCAMBIA	ACTIVE	4952	OTHER INCINERATION	H114		
490015	HARDEE POWER PARTNERS LIMITED	HARDEE POWER STATION	BOWLING GREEN	SWD	HARDEE	ACTIVE	4911	OTHER ELECTRIC PRODUCTION	H114		
490043	VANDOLAH POWER COMPANY, LLC	VANDOLAH POWER PROJECT	WAUCHULA	SWD	HARDEE	ACTIVE	4911	OTHER ELECTRIC PRODUCTION	H114	0.0005	0.0003
510004	A. DUDA & SONS, INC. / CITRUS BELLE	CITRUS BELLE	LA BELLE	SD	HENDRY	ACTIVE	2037	CITRUS PROCESSING PLANT	H114	0.0001	
530021	FLORIDA CRUSHED STONE CO., INC.	BROOKSVILLE CEMENT AND POWER PLANTS	BROOKSVILLE	SWD	HERNANDO	ACTIVE	3241 4911	PORTLAND CEMENT PLANT	H114	0.0769	0.0922
550018	TAMPA ELECTRIC COMPANY	PHILLIPS STATION	SEBRING	SD	HIGHLANDS	ACTIVE	4911	OTHER ELECTRIC PRODUCTION	H114		
570001	JOHNSON CONTROLS BATTERY GROUP, INC	JOHNSON CONTROLS BATTERY GROUP, INC	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3691	LEAD ACID BATTERY PLANT	H114	0	
570003	CF INDUSTRIES, INC.	CF INDUSTRIES, INC.	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3433	OTHER	H114		
570005	CF INDUSTRIES, INC., PLANT CITY PHOS	CF INDUSTRIES, INC., PLANT CITY PHOSP	PLANT CITY	SWHI	HILLSBOROUGH	ACTIVE	2874	PHOSPHATE FERTILIZER PLANT	H114	0	0
570006	YUENGLING BREWING CO.	YUENGLING BREWING CO.	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2082	OTHER FOOD PRODUCTION	H114	0	
570008	MOSAIC FERTILIZER, LLC	MOSAIC--RIVERVIEW FACILITY	RIVERVIEW	SWHI	HILLSBOROUGH	ACTIVE	2874	PHOSPHATE FERTILIZER PLANT	H114	0.0001	
570021	INTERNATIONAL SHIP REPAIR & MARINE SERV.	INTERNATIONAL SHIP	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3731	SURFACE COATING OPERATION	H114		
570028	NEW NGC, INC.	NEW NGC, INC.	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3275	GYPSUM PRODUCTION	H114	0.0001	
570029	KINDER MORGAN PORT SUTTON TERMINAL, LLC	KINDER MORGAN HARTFORD TERMINAL	TAMPA	SWHI	HILLSBOROUGH	INACTIVE	2873	NITRIC ACID PLANT	H114		
570038	TAMPA ELECTRIC COMPANY	HOOKERS POINT STATION	TAMPA	SWHI	HILLSBOROUGH	INACTIVE	4911	STEAM ELECTRIC PLANT	H114		
570039	TAMPA ELECTRIC COMPANY	BIG BEND STATION	APOLLO BEACH	SWHI	HILLSBOROUGH	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0.1638	
570040	TAMPA ELECTRIC COMPANY	H. L. CULBREATH BAYSIDE POWER STATION	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		

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570056	GAF MATERIALS CORPORATION	GAF MATERIALS CORPORATION	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2952	ASPHALT PLANT	H114	0	0
570057	ENVIROFOCUS TECHNOLOGIES, LLC	ENVIROFOCUS TECHNOLOGIES, LLC	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3341	SECONDARY METAL PRODUCTION	H114	0	
570061	TAMPA ARMATURE WORKS	TAMPA ARMATURE WORKS	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	7694	OTHER	H114	0	
570072	BALL METAL BEVERAGE CONTAINER CORP.	BALL METAL BEVERAGE CONTAINER CORP.	TAMPA	SWHI	HILLSBOROUGH	INACTIVE	3411	OTHER	H114		
570075	CORONET INDUSTRIES, INC.	CORONET INDUSTRIES, INC.	PLANT CITY	SWHI	HILLSBOROUGH	INACTIVE	2048 2819	OTHER CHEMICAL PLANT	H114		
570076	APAC SOUTHEAST, INC. - CENTRAL FL. DIV.	APAC, THONOTOSASSA	THONOTOSASSA	SWHI	HILLSBOROUGH	INACTIVE	2951	ASPHALT PLANT	H114	0	
570077	VERLITE COMPANY	VERLITE COMPANY	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	1521	OTHER MINERAL PROCESSING	H114		
570080	MARATHON PETROLEUM COMPANY LLC	MARATHON PETROLEUM COMPANY LLC TAMPA 02	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	5171	PETROLEUM STORAGE/TRANSFER	H114	0	
570089	ST. JOSEPH'S HOSPITAL	ST. JOSEPH'S HOSPITAL	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0.0002	0.0001
570097	OLDCASTLE RETAIL, INC. D/B/A BONSAL AMER	BONSAL AMERICAN	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3272	OTHER MINERAL PROCESSING	H114	0	
570127	CITY OF TAMPA	MCKAY BAY REFUSE-TO-ENERGY FACILITY	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	4953 0111	MUNICIPAL INCINERATION OR RRF	H114	0.0469	0.0049
570141	US AIR FORCE (MACDILL AFB)	MACDILL AFB	MACDILL AFB	SWHI	HILLSBOROUGH	ACTIVE	9711	OTHER	H114	0	0
570160	BALL METAL BEVERAGE CONTAINER CORP.	BALL METAL BEVERAGE CONTAINER CORP.	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3411	SURFACE COATING OPERATION	H114	0	
570171	SPEEDLING, INC.	SPEEDLING, INC.	SUN CITY	SWHI	HILLSBOROUGH	ACTIVE	3086 3089	OTHER	H114	0	
570223	APAC-SOUTHEAST, INC CENTRAL FLORIDA DIV.	APAC-SOUTHEAST INC, CENTRAL FLORIDA DIV.	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2951	ASPHALT PLANT	H114	0.0003	0.0004
570224	HARSCO CORPORATION	HARSCO CORPORATION	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3291	OTHER	H114		
570249	ALCOA EXTRUSIONS, INC.	ALCOA EXTRUSIONS, INC.	PLANT CITY	SWHI	HILLSBOROUGH	ACTIVE	3341 3354	SECONDARY METAL PRODUCTION	H114	0.0019	
570254	VERTIS, INC.	VERTIS, INC.	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2752	GRAPHICS ARTS/PRINTING	H114	0	
570261	HILLSBOROUGH CTY. RESOURCE RECOVERY FAC.	HILLSBOROUGH CTY. RESOURCE RECOVERY FAC.	TAMPA	SWD	HILLSBOROUGH	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.0286	0.0285
570262	CHROMALLOY CASTINGS TAMPA, CORPORATION	CHROMALLOY CASTINGS TAMPA, CORPORATION	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3369	OTHER	H114	0	
570286	TAMPA BAY SHIPBUILDING & REPAIR COMPANY	TAMPA BAY SHIPBUILDING & REPAIR COMPANY	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3731	ABRASIVE BLAST CLEANING	H114	0	0

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570287	COL. MET., INC.	COL. MET., INC.	TAMPA	SWHI	HILLSBOROUGH	INACTIVE	3479	SURFACE COATING OPERATION	H114		
570293	CORY PACKAGING, INC DBA MASTER PACKAGING	CORY PACKAGING, INC DBA MASTER PACKAGING	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2759	GRAPHICS ARTS/PRINTING	H114	0	
570320	DART CONTAINER CORPORATION OF FLORIDA	DART CONTAINER CORPORATION OF FLORIDA	PLANT CITY	SWHI	HILLSBOROUGH	ACTIVE	3086 3999	OTHER CHEMICAL PLANT	H114	0	
570321	MANTUA MANUFACTURING CO.	MANTUA MANUFACTURING CO.	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3442	SURFACE COATING OPERATION	H114		
570324	TAMPA STEEL ERECTING COMPANY	TAMPA STEEL ERECTING COMPANY	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3441 3479	SURFACE COATING OPERATION	H114		
570370	PARADISE, INC.	PARADISE, INC.	PLANT CITY	SWHI	HILLSBOROUGH	ACTIVE	2099 2064	OTHER FOOD PRODUCTION	H114	0	
570373	CITY OF TAMPA-WASTEWATER DEPT.	HOWARD F. CURREN AWT PLANT	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	4953 4952	OTHER	H114	0.0497	0.0131
570415	NEBRASKA PRINTING COMPANY INC.	NEBRASKA PRINTING CO. INC.	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2752	GRAPHICS ARTS/PRINTING	H114	0	
570417	INTERNATIONAL PAPER	INTERNATIONAL PAPER, PLANT CITY. PCKG	PLANT CITY	SWHI	HILLSBOROUGH	ACTIVE	2656	GRAPHICS ARTS/PRINTING	H114		0
570437	NEWSPAPER PRINTING COMPANY, INC.	NEWSPAPER PRINTING COMPANY, INC.	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2741	GRAPHICS ARTS/PRINTING	H114	0	
570438	FLORIDA GAS TRANSMISSION COMPANY	FGTC STATION 30 - PLANT CITY	PLANT CITY	SWHI	HILLSBOROUGH	ACTIVE	4922		H114	0	
570442	GULF MARINE REPAIR CORPORATION	GULF MARINE REPAIR	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	3731	SURFACE COATING OPERATION	H114		
570459	BAUSCH & LOMB INCORPORATED	BAUSCH & LOMB INCORPORATED	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2834	OTHER	H114	0	
570460	JAMES HARDIE BUILDING PRODUCTS, INC.	JAMES HARDIE BUILDING PRODUCTS, INC.	PLANT CITY	SWHI	HILLSBOROUGH	ACTIVE	3272	OTHER	H114	0	
570468	GATSBY SPAS INC.	GATSBY SPAS INC.	PLANT CITY	SWHI	HILLSBOROUGH	INACTIVE	3088	FIBERGLASS PRODUCTS MFG.	H114		
570480	UNIVERSITY OF SOUTH FLORIDA (USF)	UNIVERSITY OF SOUTH FLORIDA	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	8221		H114	0	
571029	WEYERHAEUSER COMPANY	WEYERHAEUSER COMPANY	PLANT CITY	SWHI	HILLSBOROUGH	ACTIVE	2653	PULP & PAPER PLANT	H114	0	
571147	SMITHFIELD FOODS, INC.	SMITHFIELD FOODS, INC.	PLANT CITY	SWHI	HILLSBOROUGH	ACTIVE	2013	OTHER FOOD PRODUCTION	H114	0	
571151	WEYERHAEUSER COMPANY	WEYERHAEUSER COMPANY	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2653		H114	0	0
571209	APAC-SOUTHEAST, INC CENTRAL FLORIDA DIV.	APAC-SOUTHEAST, INC, CENTRAL FLORIDA DIV	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2951	ASPHALT PLANT	H114	0.0001	0.0002
571240	CARGILL INC.- SALT DIVISION	CARGILL TAMPA SITE	TAMPA	SWHI	HILLSBOROUGH	ACTIVE	2899		H114	0	

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Emission Report by Facility

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Facility ID	Owner/Company Name	Site Name	City	Office	County	Status	SIC	Type	Pollutant	Actual(TPY) 2005	Actual(TPY) 2004
571242	NEW NGC, INC., D/B/A NATIONAL GYPSUM COM	NEW NGC, INC., APOLLO BEACH	GIBSONTON	SWHI	HILLSBOROUGH	ACTIVE	3275	GYPSUM PRODUCTION	H114	0.0003	
571269	H. LEE MOFFITT CANCER CENTER	H. LEE MOFFITT CANCER CENTER	TAMPA,FL.	SWHI	HILLSBOROUGH	ACTIVE	8069		H114	0	
571279	FLORIDA GAS TRANSMISSION COMPANY	FGTC STATION NO. 27, HILLSBOROUGH COUNTY	THONOTOSASSA	SWHI	HILLSBOROUGH	ACTIVE	4922		H114	0	
571320	HILLSBOROUGH COUNTY WATER DEPARTMENT	HILLS. CO. WATER DEPT - NWRMF	ODESSA	SWD	HILLSBOROUGH	CONSTRUCTION		OTHER	H114		
571321	PORT SUTTON ENVIROFUELS	PORT SUTTON ETHANOL	TAMPA	SWD	HILLSBOROUGH	CONSTRUCTION			H114		
610029	CITY OF VERO BEACH	CITY OF VERO BEACH MUNICIPAL UTILITIES	VERO BEACH	CD	INDIAN RIVER	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0	0
630014	GULF POWER COMPANY	SCHOLZ ELECTRIC GENERATING PLANT	SNEADS	NWDP	JACKSON	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
690046	COVANTA LAKE II, INC.	LAKE COUNTY RESOURCE RECOVERY FACILITY	OKAHUMPKA	CD	LAKE	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.0066	0.0038
690063	FLORIDA MEDICAL INDUSTRIES	FLORIDA MEDICAL INDUSTRIES	FRUITLAND PARK	CD	LAKE	ACTIVE	9999	OTHER	H114		
710119	LEE COUNTY DEPT. OF SOLID WASTE MGT.	LEE CO. SOLID WASTE RESOURCE REC. FAC.	FORT MYERS	SD	LEE	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.044	0 0327
710236	BONITA SPRINGS UTILITIES INC	EAST WATER RECLAMATION FACILITY	BONITA SPRINGS, FL	SD	LEE	CONSTRUCTION	9511	OTHER	H114		
730071	RECYCLIGHTS, INC.	RECYCLIGHTS, INC.	TALLAHASSEE	NWDT	LEON	INACTIVE	3341	OTHER	H114		
730099	LEON COUNTY	SOLID WASTE MANAGEMENT FACILITY	TALLAHASSEE	NWDT	LEON	ACTIVE	4953	MUNICIPAL SOLID WASTE LANDFILL	H114	0.0001	0.0001
790011	PERPETUAL ENERGY CORP OF FLORIDA	PERPETUAL ENERGY CORP OF FLORIDA	MADISON	NED	MADISON	INACTIVE	4911	STEAM ELECTRIC PLANT	H114		
810030	EATON AEROSPACE LLC	EATON AEROSPACE LLC	SARASOTA	SWD	MANATEE	ACTIVE	3679	OTHER	H114	0	0
810055	MANATEE COUNTY UTILITY OPERATIONS DEPT.	MANATEE COUNTY LENA RD LANDFILL	BRADENTON	SWD	MANATEE	ACTIVE	4953	MUNICIPAL SOLID WASTE LANDFILL	H114	0.0002	0.0002
810213	UNITES STATES ENVIRONFUELS, LLC	PORT MANATEE ETHANOL FACILITY	PALMETTO	SWD	MANATEE	CONSTRUCTION	2869	OTHER CHEMICAL PLANT	H114		
830024	LOCKHEED MARTIN MISSILES & FIRE CONTROL	LOCKHEED MARTIN/OCALA	OCALA	CD	MARION	ACTIVE	3679 3728 3812	OTHER	H114		
850001	FLORIDA POWER & LIGHT (PMR)	MARTIN POWER PLANT	INDIANTOWN	SED	MARTIN	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0.0063	
850102	INDIANTOWN COGENERATION, L.P.	INDIANTOWN COGENERATION PLANT	INDIANTOWN	SED	MARTIN	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0.0177	0.02
870047	CITY OF KEY WEST	SOUTHERNMOST WASTE TO ENERGY FACILITY	KEY WEST	SD	MONROE	INACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114		

TABLE H-15a
FLORIDA MERCURY EMISSION INVENTORY

Emission Report by Facility

Data for this Report is One Day Old Production Data.

Facility ID	Owner/Company Name	Site Name	City	Office	County	Status	SIC	Type	Pollutant	Actual(TPY) 2005	Actual(TPY) 2004
870058	CITY OF KEY WEST	TRUMBO POINT ANNEX	KEY WEST FL	SD	MONROE	INACTIVE	4953	OTHER INCINERATION	H114		
890003	SMURFIT-STONE CONTAINER ENTERPRISES, INC	SMURFIT-STONE CONTAINER ENTERPRISES, INC	FERNANDINA BEACH	NED	NASSAU	ACTIVE	2631	PULP & PAPER PLANT	H114	0.01	0.0124
890004	RAYONIER PERFORMANCE FIBERS LLC	FERNANDINA SULFITE MILL	FERNANDINA BEACH	NED	NASSAU	ACTIVE	2611	PULP & PAPER PLANT	H114		
950137	ORLANDO UTILITIES COMMISSION	STANTON ENERGY CENTER	ORLANDO	CD	ORANGE	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0.1048	0.0971
950169	STERICYCLE INC	STERICYCLE/APOPKA FACILITY	APOPKA	CDOR	ORANGE	ACTIVE	4953	PATHOLOGICAL INCINERATOR	H114	0.0007	0
950189	FLORIDA BIO-COMPLIANCE, INC.	FLORIDA BOI-COMPLIANCE, INC.	ORLANDO	CDOR	ORANGE	INACTIVE	4953	PATHOLOGICAL INCINERATOR	H114		
950203	ORLANDO COGEN LIMITED, L.P.	ORLANDO COGEN LIMITED, L.P.	ORLANDO	CDOR	ORANGE	ACTIVE	4931	STEAM ELECTRIC PLANT	H114	0	0
970014	FLORIDA POWER CORPORATION D/B/A PROGRESS	INTERCESSION CITY PLANT	INTERCESSION CITY	CD	OSCEOLA	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
970043	KISSIMMEE UTILITY AUTHORITY	KUA CANE ISLAND POWER PARK	INTERCESSION CITY/OSCEOLA	CD	OSCEOLA	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0	0
970079	OMNI WASTE OF OSCEOLA COUNTY, LLC	OAK HAMMOCK DISPOSAL FACILITY	ST. CLOUD	CD	OSCEOLA	ACTIVE	4953	MUNICIPAL SOLID WASTE LANDFILL	H114	0	0
990045	CITY OF LAKE WORTH UTILITIES	TOM G. SMITH POWER PLANT	LAKE WORTH	SEPB	PALM BEACH	ACTIVE	4931	STEAM ELECTRIC PLANT	H114	0	0
990095	BETHESDA MEMORIAL HOSPITAL	BETHESDA MEMORIAL HOSPITAL	BOYNTON BEACH	SEPB	PALM BEACH	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0	0.001
990119	BOCA RATON COMMUNITY HOSPITAL	BOCA RATON COMMUNITY HOSPITAL	BOCA RATON	SEPB	PALM BEACH	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0.0001	0.0001
990234	SOLID WASTE AUTHORITY OF PBC	SOLID WASTE AUTHORITY OF PBC/NCRRF	WEST PALM BEACH	SED	PALM BEACH	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.0209	0.0325
990304	DEPARTMENT OF VETERANS AFFAIRS	VETERANS AFFAIRS MEDICAL CENTER	WEST PALM BEACH	SEPB	PALM BEACH	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114		
990331	PALM BEACH POWER CORP.	OSCEOLA COGENERATION PLANT (INACTIVE)	SOUTH BAY	SEPB	PALM BEACH	INACTIVE	4911	STEAM ELECTRIC PLANT	H114		
990332	NEW HOPE POWER PARTNERSHIP	OKEELANTA COGENERATION PLANT	SOUTH BAY	SEPB	PALM BEACH	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0.0039	0.0034
1010056	PASCO COUNTY	PASCO COUNTY RESOURCE RECOVERY FACILITY	SPRING HILL	SWD	PASCO	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.0289	0.0163
1010071	PASCO COGEN LIMITED	PASCO COGEN LIMITED	DADE CITY	SWD	PASCO	ACTIVE	4931	OTHER ELECTRIC PRODUCTION	H114		
1030004	APAC- SOUTHEAST, INC. -CENTRAL FL. DIV	TAMPA BRANCH - PLANT 450	CLEARWATER	SWPN	PINELLAS	ACTIVE	2951	ASPHALT PLANT	H114	0	0
1030011	FLORIDA POWER CORPOBAPROGRESS ENERGY FLA	BARTOW PLANT	ST PETERSBURG	SWPN	PINELLAS	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		

TABLE H-15a
FLORIDA MERCURY EMISSION INVENTORY

Emission Report by Facility

Data for this Report is One Day Old Production Data.

Facility ID	Owner/Company Name	Site Name	City	Office	County	Status	SIC	Type	Pollutant	Actual(TPY) 2005	Actual(TPY) 2004
1030012	FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	HIGGINS PLANT	OLDSMAR	SWPN	PINELLAS	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
1030013	FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	BAYBORO POWER PLANT	ST. PETERSBURG	SWPN	PINELLAS	ACTIVE	4911	OTHER ELECTRIC PRODUCTION	H114		
1030044	SUNCOAST PAVING, INC.	TARPON SPRINGS FACILITY	TARPON SPRINGS	SWPN	PINELLAS	ACTIVE	2951	ASPHALT PLANT	H114		
1030060	CITY OF LARGO - WWTP	CITY OF LARGO WASTEWATER TREATMENT PLANT	CLEARWATER	SWPN	PINELLAS	ACTIVE	4952	OTHER	H114	0.0002	0.0002
1030091	MORTON PLANT MEASE HEALTH CARE	MORTON PLANT MEASE HEALTH CARE	CLEARWATER	SWPN	PINELLAS	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114		
1030095	BAYFRONT-ST. ANTHONY'S HEALTH CARE	BAYFRONT MEDICAL CENTER	ST PETERSBURG	SWPN	PINELLAS	ACTIVE	8062	PATHOLOGICAL INCINERATOR	H114	0	0
1030112	CARDINAL HEALTH PTS, LLC	CARDINAL HEALTH PTS, LLC	ST. PETERSBURG	SWPN	PINELLAS	ACTIVE	2834 2833	OTHER	H114		
1030117	PINELLAS CO. BOARD OF CO. COMMISSIONERS	PINELLAS CO. RESOURCE RECOVERY FACILITY	ST. PETERSBURG	SWD	PINELLAS	ACTIVE	4953	MUNICIPAL INCINERATION OR RRF	H114	0.2677	0.057
1030140	METAL INDUSTRIES, INC.	METAL INDUSTRIES - TARPON SPRINGS	TARPON SPRINGS	SWPN	PINELLAS	INACTIVE	3446	SURFACE COATING OPERATION	H114		
1030210	MEDICO ENVIRONMENTAL SERVICES, INC.	MEDICO ENVIRONMENTAL SERVICES, INC.	CLEARWATER	SWPN	PINELLAS	ACTIVE	4953	PATHOLOGICAL INCINERATOR	H114	0.0002	0.0002
1030214	LIFOAM INDUSTRIES, LLC.	LIFOAM INDUSTRIES, LLC.	ST PETERSBURG	SWPN	PINELLAS	ACTIVE	3086	OTHER	H114		
1030234	PINELLAS COUNTY GOVERNMENT	SOUTH CROSS BAYOU WATER RECLAMATION FAC	ST. PETERSBURG	SWD	PINELLAS	ACTIVE	4952	OTHER	H114	0.0008	0.0008
1030250	NTU ELECTRONICS, INC	NTU ELECTRONICS, INC.	LARGO	SWPN	PINELLAS	ACTIVE	3679	OTHER	H114		
1050003	LAKELAND ELECTRIC	CHARLES LARSEN MEMORIAL POWER PLANT	LAKELAND	SWD	POLK	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0	0
1050004	LAKELAND ELECTRIC	C.D. MCINTOSH, JR. POWER PLANT	LAKELAND	SWD	POLK	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
1050072	WINTER HAVEN HOSPITAL	WINTER HAVEN HOSPITAL	WINTER HAVEN	SWD	POLK	INACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0.0006	0.0006
1050095	LAKELAND REGIONAL MEDICAL CENTER	LAKELAND REGIONAL MEDICAL CENTER	LAKELAND	SWD	POLK	ACTIVE	8062	HOSPITALS/HEALTH CARE	H114	0	0
1050216	WHEELABRATOR RIDGE ENERGY INC.	RIDGE GENERATING STATION	AUBURNDALE	SWD	POLK	ACTIVE	4911	STEAM ELECTRIC PLANT	H114	0.001	0.0011
1050221	CALPINE/AUBURNDALE POWER PARTNERS, LP	AUBURNDALE COGENERATION FACILITY	AUBURNDALE	SWD	POLK	ACTIVE	4911	OTHER ELECTRIC PRODUCTION	H114		
1050223	FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	TIGER BAY COGENERATION FACILITY	FT. MEADE	SWD	POLK	ACTIVE	4911 4961	OTHER ELECTRIC PRODUCTION	H114	0.0009	0.0011
1050233	TAMPA ELECTRIC COMPANY	POLK POWER STATION	MULBERRY	SWD	POLK	ACTIVE	4911	OTHER ELECTRIC PRODUCTION	H114	0.0335	0.0437

TABLE H-15a
FLORIDA MERCURY EMISSION INVENTORY

Emission Report by Facility

Data for this Report is One Day Old Production Data.

Facility ID	Owner/Company Name	Site Name	City	Office	County	Status	SIC	Type	Pollutant	Actual(TPY) 2005	Actual(TPY) 2004
1050234	FLORIDA POWER CORPDBAPROGRESS ENGERY FLA	HINES ENERGY COMPLEX	BARTOW	SWD	POLK	ACTIVE	4911	OTHER ELECTRIC PRODUCTION	H114	0.0026	0.0021
1070005	GEORGIA-PACIFIC CONSUMER PRODUCTS LLC	PALATKA PULP & PAPER MILL	PALATKA	NED	PUTNAM	ACTIVE	2621	PULP & PAPER PLANT	H114	0.0049	
1150089	SARASOTA CO BD OF CO COMM	SARASOTA CTY CENT CTY SW DISPOSAL CMPLX	NOKOMIS	SWD	SARASOTA	ACTIVE	4953	MUNICIPAL SOLID WASTE LANDFILL	H114		0.0001
1150090	SARASOTA CO. BOARD OF COUNTY COMM'S	SARASOTA CO. BEE RIDGE LANDFILL	SARASOTA	SWD	SARASOTA	ACTIVE	4953	MUNICIPAL SOLID WASTE LANDFILL	H114		0.0001
1190042	AMERICAN CEMENT COMPANY, LLC	SUMTERVILLE CEMENT PLANT	SUMTERVILLE	SWD	SUMTER	CONSTRUCTION		PORTLAND CEMENT PLANT	H114		
1210003	FLORIDA POWER CORPDBAPROGRESS ENERGY FLA	FL POWER SUWANNEE RVR PLANT	LIVE OAK	NED	SUWANNEE	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
1210465	SUWANNEE AMERICAN CEMENT CO.	SUWANNEE AMERICAN CEMENT	BRANFORD	NED	SUWANNEE	ACTIVE	3241	PORTLAND CEMENT PLANT	H114	0.0406	0.0252
1230033	GILMAN BUILDING PRODUCTS	GILMAN BUILDING PRODUCTS	PERRY	NED	TAYLOR	ACTIVE	2421	MISC WOOD PRODUCTS MFG.	H114		
1270028	FLORIDA POWER CORPORATION D/B/A PROGRESS	DEBARY FACILITY	DEBARY	CD	VOLUSIA	ACTIVE	4911	STEAM ELECTRIC PLANT	H114		
7770242	APAC-SOUTHEAST, INC.	APAC-SOUTHEAST, INC. FIRST COAST DIV.	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2951	ASPHALT PLANT	H114		
7775041	APAC- SOUTHEAST, INC.	APAC-SOUTHEAST, INC.	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2951	ASPHALT PLANT	H114		
7775082	SOUTHERN PAVEMENTS, LLC	SOUTHERN PAVEMENTS, LLC	JACKSONVILLE	NEDV	DUVAL	INACTIVE	2951	ASPHALT PLANT	H114	0.0001	0.0003
7775108	DUVAL ASPHALT PRODUCTS, INC.	6820 WEST 12 TH STREET	JACKSONVILLE	NEDV	DUVAL	ACTIVE	2951	ASPHALT PLANT	H114	0.0003	
										1.3761	

You entered the following criteria
Pollutant = H114
Year = 2005
Order By = Facility ID

Report Run Date: 2/2/2007

TABLE FDEP-15b

2005 REPORTED MERCURY EMISSIONS IN SOUTHERN PENINSULA OF FLORIDA BASED ON ANNUAL OPERATING REPORTS SUBMITTED TO FDEP

FAC ID	COMPANY NAME	SITE NAME	SIC	CITY	COUNTY	2005 AOR H114 (TPY)
1030095	BAYFRONT-ST. ANTHONY'S HEALTH CARE	BAYFRONT MEDICAL CENTER	8062	St. Pete	Pinellas	0.000026
0990095	BETHESDA MEMORIAL HOSPITAL	BETHESDA MEMORIAL HOSPITAL	8062	Boynton Beach	Palm Beach	0.000020
0990119	BOCA RATON COMMUNITY HOSPITAL	BOCA RATON COMMUNITY HOSPITAL	8062	Boca Raton	Palm Beach	0.000062
0990045	CITY OF LAKE WORTH	TOM G. SMITH POWER PLANT	4931	Lake Worth	Palm Beach	0.000031
0570127	CITY OF TAMPA	MCKAY BAY REFUSE-TO-ENERGY FACILITY	4953	Tampa	Hillsborough	0.046941
0110037	FLORIDA POWER	Ft Lauderdale Power Plant	4911	Ft Lauderdale	Broward	0.006365
0850001	FLORIDA POWER	Martin Power Plant	4911	Indiantown	Martin	0.006294
1050223	FLORIDA POWER	TIGER BAY COGENERATION FACILITY	4911	Ft. Meade	Polk	0.000884
1050234	FLORIDA POWER	HINES ENERGY COMPLEX	4911	Bartow	Polk	0.002557
0111019	HOLY CROSS HOSPITAL	HOLY CROSS HOSPITAL	8062	Ft. Lauderdale	Broward	0.000008
0850102	Indiantown Cogeneration	Indiantown Cogeneration Plant	4911	Indiantown	Martin	0.017654
0490043	IPS AVON PARK CORPORATION	IPS VANDOLAH POWER PROJECT	4911	Wachula	Hardee	0.000475
0970043	KISSIMMEE UTILITY AUTHORITY	KUA CANE ISLAND POWER PARK	4911	Intercession City	Osceola	0.000001
1050003	LAKELAND ELECTRIC	CHARLES LARSEN MEMORIAL POWER PLANT	4911	Lakeland	Polk	0.000042
1050095	LAKELAND REGIONAL MEDICAL CENTER	LAKELAND REGIONAL MEDICAL CENTER	8062	Lakeland	Polk	0.000030
0710119	LEE COUNTY DEPT OF SOLID WASTE MGT.	LEE CO SOLID WASTE RESOURCE REC. FAC.	4953	Fort Myers	Lee	0.044400
0810055	MANATEE COUNTY UTILITY OPERATIONS DEPT.	MANATEE COUNTY LENA RD LANDFILL	4953	Bradenton	Manatee	0.000017
0110002	MEMORIAL REGIO HOSP/SO BROWARD HOSP DIST	MEMORIAL REGIO HOSP/SO BROWARD HOSP DIST	8062	Hollywood	Broward	0.000001
0250337	MERCY HOSPITAL	MERCY HOSPITAL	8062	Miami	Miami-Dade	0.000007
0250348	Miami-Dade RRF	Miami-Dade RRF Montenay	4953	Miami	Miami-Dade	0.000977
0990332	New Hope Power Partnership	Okeelanta Cogen Plant	4911	South Bay	Palm Beach	0.003910
0950137	ORLANDO UTILITIES COMMISSION	STANTON ENERGY CENTER	4911	Orlando	Orange	0.104827
1030117	PINELLAS CO. BOARD OF CO COMMISSIONERS	PINELLAS CO. RESOURCE RECOVERY FACILITY	4953	St. Pete	Pinellas	0.267670
0990234	SOLID WASTE AUTHORITY OF PBC	NCRRF	4953	West Palm Beach	Palm Beach	0.020894
0570089	ST JOSEPH'S HOSPITAL	ST. JOSEPH'S HOSPITAL	8062	Tampa	Hillsborough	0.000162
0570039	TAMPA ELECTRIC COMPANY	TECO BIG BEND STATION	4911	Apollo Beach	Hillsborough	0.163757
1050233	TAMPA ELECTRIC COMPANY	POLK POWER STATION	4911	Mulberry	Polk	0.033480
0112119	WHEELABRATOR	Wheelabrator South Broward	4953	Ft. Lauderdale	Broward	0.129749
0112120	WHEELABRATOR	Wheelabrator North Broward	4953	Pompano Beach	Broward	0.035193
1050216	WHEELABRATOR	RIDGE GENERATING STATION	4911	Auburndale	Polk	0.001000
					Total	0.887434

Note: The "Southern Peninsula" of Florida refers to the following counties and south: Pinnellas, Hillsborough, Polk, Orange and Brevard

Source FDEP, 2006.

TABLE FDEP-15c
POTENTIAL MECURY EMISSIONS FROM SOUTH FLORIDA RRF AND FGPP

Facility.		Hg Emissions	Heat Input
Miami-Dade County RRF		640 pounds per year	972 MMBtu/hr
South Broward RRF		540 pounds per year	971 MMBtu/hr
North Broward RRF		480 pounds per year	840 MMBtu/hr
Palm Beach RRF		360 pounds per year	825 MMBtu/hr
Lee County RRF		811 pounds per year	842 MMBtu/hr
	Total:	*2,831* pounds per year	*4,449* MMBtu/hr
FGPP		184 pounds per year	17,400 MMBtu/hr

Note: Reported Hg Emissions in 2005 for the 5 RRFs are: 462.4 pounds per year.

ATTACHMENT FDEP-26

PRELIMINARY START-UP PROTOCOL

Attachment H-26
Preliminary - FPL Glades Power Park
Unit Startup and Shutdown Emissions Minimization Protocol

1. General Operating Protocol Description

The intent of the unit startup and shutdown emissions protocol is to minimize the duration and extent of emissions during periods of steam generator startup and shutdown.

1.1. Startup General Description

As a precursor to firing the steam generator, chemistry of the water circulated within the pre-boiler and steam generator water side circuits must meet the steam generator supplier's requirements. The dissolved oxygen content of the water must be at an extremely low concentration. To meet this requirement, the deaerator is placed in service and vacuum is established in the condenser. Steam produced by the auxiliary boiler provides the motive steam for these functions. Pre-boiler and steam generator water circuit cleanup may take 2 to 3 days during a cold startup.

When the proper water chemistry requirements are met, the steam generator may be fired. The wet electrostatic precipitator (WESP) and wet fuel gas desulphurization (WFGD) equipment can be initialized at any time prior to light off of the steam generator.

Fuel oil is the initial heat input source used during steam generator warm up, and unit startup begins when fuel oil is introduced into the steam generator. Fuel oil is introduced via ignitors and warm up burners. When steam is produced at required pressure and temperature, pre-warm up of the steam turbine begins. Once pre-warmed, the steam turbine is rolled and continues through various lengthy speed heat soaks to continue to bring the turbine components up to operating temperature. Steam generator firing rate increases to approximately 30% on fuel oil throughout this period. The steam turbine generator is then synchronized and continues to heat up during a minimum load hold. Coal firing would typically begin at this time. Each coal pulverizer is then individually brought into service concurrently with supporting fuel oil firing. As pulverizer firing rate exceeds the minimum (approximately 40%) and the combustion process stabilizes, its supporting fuel oil fired ignitors are shutdown. As unit load exceeds approximately 40%, any remaining operating warm up burners firing fuel oil are shut down. The remaining pulverizers are brought into service one at a time, supported by fuel oil fired ignitors, until their respective firing rates exceed the minimum requirement (approximately 40%). When the minimum required SCR inlet temperature is attained (approximately 70% unit load) ammonia injection may begin.

Unit startup ends when the ignitors supporting the last pulverizer are stopped. Startup does not extend beyond 24 hours for a cold startup, 14 hours for a warm startup and 6 hours for a hot startup.

Although the equipment is not fully effective until proper temperatures and stable conditions are reached, startup emissions are minimized by placing the wet electrostatic precipitator and flue gas desulfurization scrubber in service prior to the introduction of fuel to the boiler. Placing the electrostatic precipitator in service early in the process provides for a reduction in particulate matter emissions; however, caution must be exercised to ensure that the bag house filters, WESP collection plates and wires are not fouled with fuel oil, which would have a long-term detrimental affect on the precipitator's performance. Placing the scrubber in service prior to firing fuel has the advantage of reducing sulfur dioxide emissions as well as aiding in the removal of particulate matter emissions. The disadvantage of this practice is that additional moisture is introduced into the flue gas stream and at the low stack temperatures encountered early during the startup period, there is a potential that moisture will interfere with the opacity monitor readings.

1.2. Shutdown General Description

Unit shutdown begins when the unit load or output is reduced with the intent of removing the unit from service, or when the unit trips as the result of a sudden and unforeseen failure or malfunction. Shutdown ends at the point when fuel input to the steam generator ceases. During a normal shutdown, fuel oil ignition support is utilized to stabilize coal combustion. The ignitors are brought into service as individual pulverizer firing rate is reduced to minimum (around 40% capacity). Pulverizers are typically removed from service individually, although emergencies such as a steam generator tube leak may require that all pulverizers enter a shutdown sequence concurrently. As unit load approaches minimum (30 to 40% unit load), the fuel oil warm up burners may be brought into service to stabilize the steam turbine generator load while the pulverizers are being shut down. Once unit load is decreased sufficiently to result in the SCR inlet temperature dropping below the required minimum, ammonia injection is ceased. After the last pulverizer has been shut down, the steam turbine generator load is decreased to minimum and the generator is taken off line. Remaining fuel oil ignitors and warm up burners are then stopped, ending the unit shutdown. It is anticipated that normal unit shutdowns will last two to three hours in duration.

During unplanned shutdown events, such as a unit trip, the generator or steam generator will abruptly trip and be immediately removed from operation. These are unforeseen events of extremely short duration. If a unit trip occurs, either due to a steam generator, steam turbine generator, power grid, or auxiliary equipment malfunction, fuel input to the steam generator will immediately cease and shutdown will instantaneously occur.

2. Startup Emission Minimization

The Plant utilizes work practices to minimize emissions during startup events. Pollution control equipment, including the wet electrostatic precipitator and flue gas desulfurization scrubber, is placed into service prior to the firing of fuel in the steam generator during a startup event.

3. Reporting and Recordkeeping

Startup and shutdown emissions will be controlled by minimizing the frequency and duration of plant startup and shutdown events. Records will be maintained that document the number and duration of individual startup and shutdown events.

Plant personnel will record each boiler unit startup event and log the following information:

3.1. The unit undergoing startup

3.2. The date, time and duration of each startup episode including:

- 3.2.1. The start time of the startup event (initiation of steam generator fuel oil firing)
- 3.2.2. The end time of the startup event, which is no later than the point in time when the ignitors have been removed from the last pulverizer started.
- 3.2.3. The total duration of a startup event. The total duration of an individual startup event is not to exceed 24 hours for a cold startup, 14 hours for a warm startup and 6 hours for a hot startup.

Plant personnel will record each boiler unit shutdown event and log the following information:

3.3. The unit undergoing shutdown

3.4. The date, time and duration of each shutdown episode including:

3.4.1. The start time of the shutdown event
3.4.2. The end time of the shutdown event

4. Summary

Sections 1, 2 and 3 have defined unit startup and shutdown at the Plant. These sections have also identified work practices that Plant personnel utilize to minimize emissions during boiler startup and shutdown events. These work practices include ensuring that appropriate pollution control equipment, including fabric filters, electrostatic precipitators and FGD scrubbers are operational prior to the introduction of fuel to the boiler during a startup event.

An evaluation of the maximum potential emission rates during a startup event is much less than the unit-specific permitted values. Additionally, actual emissions are not uncontrolled during a startup since the fabric filter, wet electrostatic precipitator and scrubber are operational.

Records will be maintained as indicated in Section 4 to document the date, time and duration of each unit startup and shutdown event, as well as the total annual duration of unit startup events, on a unit-specific basis.

ATTACHMENT FDEP-29

EMISSIONS OF HAPS

TABLE FDEP-29
SUMMARY OF AIR EMISSIONS CATEGORIZED AS HAZARDOUS AIR POLLUTANTS USING EPA AP-42 EMISSION FACTORS-FGPP

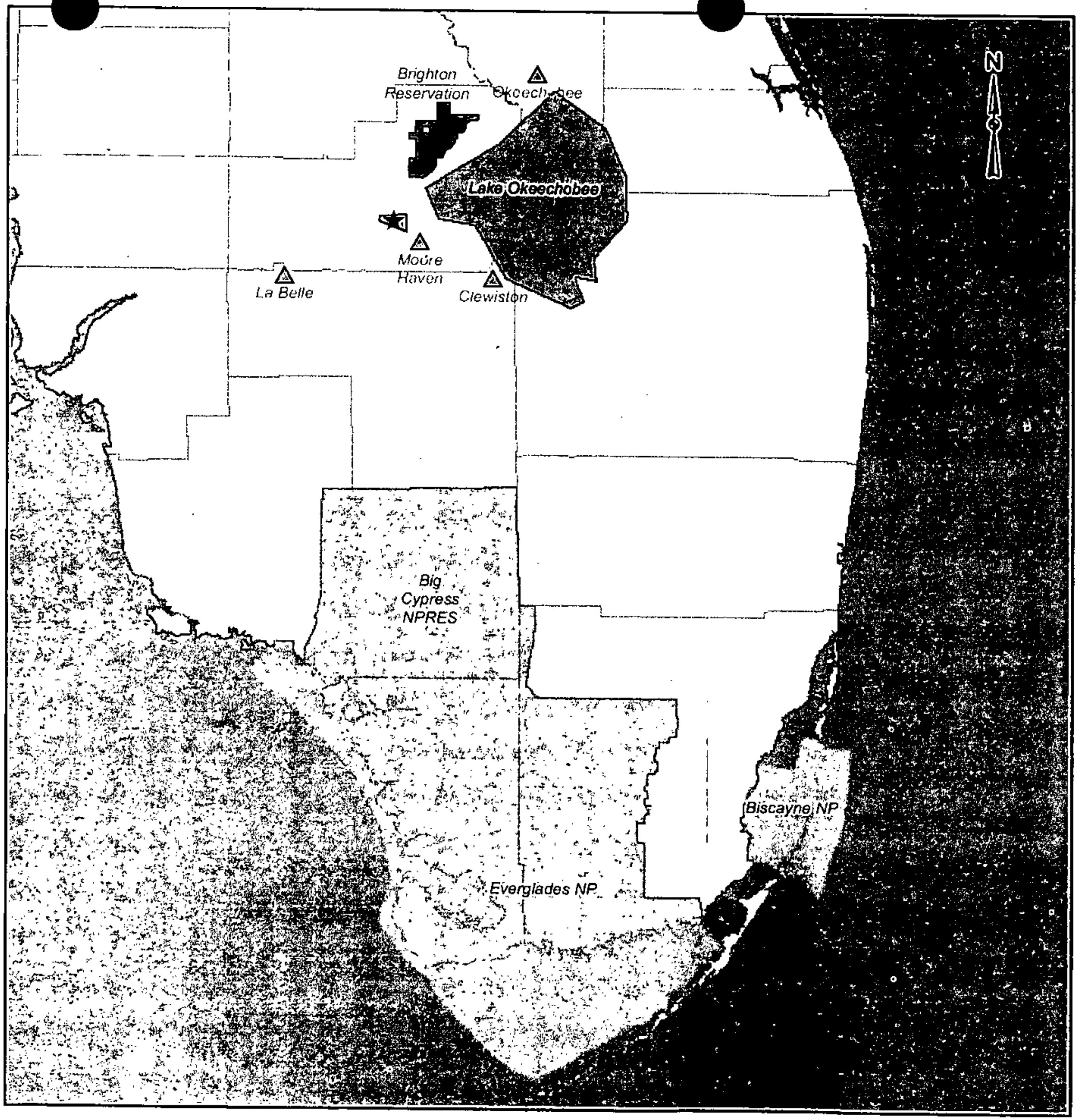
HAP Category	Elements	Tons/Year
Metals	As, Be, Cd, Cr, Co, Hg, Pb, Mn, Ni, Sb, and Se	3.9114298
Halogens	HCl and HF	207.69214
Dioxins	PCDDs and PCDFs as	5.94E-06
Organics	39 compounds from AP-42 Emission Factors	31.027996
	Total:	242.63157

Note: Radionuclides emissions are not based on mass emissons but picrocuries per gram of particulate matter emitted. The annual amount was 5.48×10^{10} pC/yr.

Source: Tables HAPS-1 through HAPS-4; Air Construction/PSD Permit Application in Appendix A; Same information in Appendix 10.1.5 of SCA

ATTACHMENT FDEP-30

AREA MAP OF FGPP



LEGEND

- ★ Location of FGPP Stacks
- FGPP Boundary
- Brighton Indian Reservation
- △ Nearby Cities
- Major Lakes
- National Parks

Location	Distance (mi)
Moore Haven	5
Lake Okeechobee	6
Brighton Indian Reservation	7
Clewiston	17
La Belle	18
Okeechobee	32
Big Cypress Preserve	44
Everglades National Park	70
Biscayne National Park	103

REFERENCE

20 0 20 Miles

PROJECT

FPL Glades Power Project

TITLE

Area Map

FPL

PROJECT No. 063-7597			SCALE AS SHOWN	REV 0
DESIGN	AB	26 Feb 2007	FDEP-30	
GIS	AB	26 Feb 2007		
CHECK	SM	26 Feb 2007		
REVIEW	KK	26 Feb 2007		

ATTACHMENT FDEP-31

AIR IMPACT FIGURES

LEGEND

Project Boundary

Anuual SO_2 Results

FGPP Impact

PSD Class II Increment

AAQS

FGPP Maximum Impact = 0.6 μg/m^3

Percent of Maximum Contours

75% of Max

50% of Max

25% of Max

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

2,600 0 2,600 Meters

PROJECT

FPL Glades Power Project

TITLE

Annual SO_2 Results

FPL

PROJECT No.		
DESIGN	AB	15 Feb. 2007
GIS	AB	15 Feb. 2007
CHECK	BM	15 Feb. 2007
REVIEW	KK	15 Feb. 2007

SCALE AS SHOWN | REV 0

FIGURE 1

LEGEND

Project Boundary

24-Hour SO_2 Results

FGPP Impact

PSD Class II Increment

AAQS

FGPP Maximum Impact = 5.2 $\mu g/m^3$

Percent of Maximum Contours

75% of Max

50% of Max

25% of Max

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

2,750 0 2,750 Meters

PROJECT

FPL Glades Power Project

TITLE

24-Hour SO_2 Results

PROJECT No			SCALE AS SHOWN	REV 0
DESIGN	AB	15 Feb. 2007		
GIS	AB	15 Feb. 2007		
CHECK	BM	15 Feb. 2007		
REVIEW	KK	15 Feb. 2007		

FPL

FIGURE 2

LEGEND

Project Boundary

Anuual PM_{10} Results

FGPP Impact

PSD Class II Increment

AAQS

FGPP Maximum Impact = 0.8 μg/m^3

Percent of Maximum Contours

75% of Max

50% of Max

25% of Max

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

2,900 0 2,900 Meters

PROJECT	
FPL Glades Power Project	
TITLE	
Annual PM_{10} Results	

PROJECT No			SCALE AS SHOWN	REV 0
DESIGN	AB	15 Feb. 2007		
GIS	AB	15 Feb. 2007		
CHECK	BM	15 Feb. 2007	**FIGURE 3**	
REVIEW	KK	15 Feb. 2007		

FPL

LEGEND

- Project Boundary

24-Hour PM_{10} Results

- FGPP Impact
- PSD Class II Increment
- AAQS

FGPP Maximum Impact = 6.9 μg/m^3

Percent of Maximum Contours

- 75% of Max
- 50% of Max
- 25% of Max

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

2,600 0 2,600 Meters

PROJECT				
FPL Glades Power Project				
TITLE				
24-Hour PM_{10} Results				
FPL	PROJECT No			SCALE AS SHOWN / REV 0
	DESIGN	AB	15 Feb. 2007	**FIGURE 4**
	GIS	AB	15 Feb. 2007	
	CHECK	BM	15 Feb. 2007	
	REVIEW	KK	15 Feb. 2007	

LEGEND

Project Boundary

Annual NO_x Results

FGPP Impact

PSD Class II Increment

AAQS

FGPP Maximum Impact = 0.7 μg/m^3

Percent of Maximum Contours

75% of Max

50% of Max

25% of Max

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

2,700 0 2,700 Meters

PROJECT

FPL Glades Power Project

TITLE

Annual NO_x Results

PROJECT No.			SCALE AS SHOWN	REV. 0
DESIGN	AB	15 Feb. 2007		
GIS	AB	15 Feb. 2007		
CHECK	BM	15 Feb. 2007		
REVIEW	KK	15 Feb. 2007		

FPL

FIGURE 5

ATTACHMENT FDEP-35

CLASS I MODELING

TABLE 5.6.1-1 (FDEP-35)
SUMMARY OF THE SIGNIFICANT IMPACT ANALYSIS FOR FGPP PROPOSED BOILERS PSD CLASS II AND PM MATERIAL HANDLING OPERATIONS

Pollutant, Averaging Time, and Rank	Maximum Predicted Concentration ($\mu g/m^3$)			Significant Impact Level ($\mu g/m^3$)
	100% Load	70% Load	40% Load	
PROPOSED BOILERS ONLY				
SO_2				
Annual, Highest	0.55	0.50	0.42	1
24-Hour, Highest	5.16	4.82	3.87	5
3-Hour, Highest [a]	24.1	21.9	17.8	25
PM_{10}				
Annual, Highest	0.25	0.23	0.19	1
24-Hour, Highest	2.32	2.17	1.74	5
NO_x				
Annual, Highest	0.69	0.63	0.53	1
CO				
8-Hour, Highest	42.1	41.6	34.8	500
1-Hour, Highest	103.5	87.1	70.0	2000
PROPOSED BOILERS AND PM MATERIAL HANDLING OPERATIONS				
PM_{10}				
Annual, Highest	0.80	NM	NM	1
24-Hour, Highest	6.89	NM	NM	5

Note: NM= not modeled.

[a] Based on 3-hour average SO_2 emission rate of 0.065 lb/MMBtu.

TABLE 5.6.1-2 (FDEP-35)
MAXIMUM CONCENTRATIONS PREDICTED FOR FGPP
AT THE PSD CLASS I AREAS OF THE EVERGLADES NP AND CHASSAHOWITZKA NWA
BASED ON EPA VERSION OF CALPUFF

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m3) a 2001	2002	2003	EPA Class I Significant Impact Levels (ug/m^3)	PSD Class I Increment (ug/m^3)
Everglades NP						
SO_2	Annual	0.011	0.015	0.013	0.1	2
	24-Hour	0.42	0.39	0.36	0.2	5
	3-Hour [b]	2.61	2.08	2.30	1.0	25
PM_{10}	Annual	0.004	0.006	0.005	0.2	4
	24-Hour	0.15	0.18	0.13	0.3	8
NO_2	Annual	0.006	0.005	0.006	0.1	2.5
Chassahowitzka NWA						
SO_2	Annual	0.007	0.010	0.007	0.1	2
	24-Hour	0.16	0.19	0.13	0.2	5
	3-Hour [b]	1.00	1.13	0.76	1.0	25
PM_{10}	Annual	0.003	0.004	0.003	0.2	4
	24-Hour	0.068	0.079	0.059	0.3	8
NO_2	Annual	0.002	0.003	0.001	0.1	2.5

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model version 5.711a and 3 years of meteorological data, 2001 to 2003, developd by VISTAS.

[b] Based on 3-hour average SO_2 emission rate of 0.065 lb/MMBtu.

TABLE 5.6.1-5 (FDEP-35)
MAXIMUM PREDICTED CUMULATIVE SO_2 CONCENTRATIONS FOR COMPARISON TO THE PSD CLASS I INCREMENTS AT THE PSD CLASS I AREA OF THE EVERGLADES NP BASED ON EPA VERSION OF CALPUFF

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m^3) [a] 2001	2002	2003	PSD Class I Increment (ug/m^3)
Everglades NP					
SO_2	24-Hour	3.67	3.00	4.58	5
	3-Hour [b]	8.05	8.42	9.60	25

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model version 5.711a and three years of meteorological data, 2001 to 2003, developd by VISTAS.

[b] Project modeled with 3-hour average SO_2 emission rate of 0.065 lb/MMBtu.

TABLE 5.6.1-6 (FDEP-35)
MAXIMUM CONCENTRATIONS PREDICTED FOR FGPP
AT THE BIG CYPRESS NATIONAL PRESERVE AND BISCAYNE NATIONAL PARK

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m^3) [a] 2001	2002	2003	EPA Class II Significant Impact Levels (ug/m^3)	PSD Class II Increment (ug/m^3)
Big Cypress National Preserve						
SO_2	Annual	0.015	0.022	0.020	1	20
	24-Hour	0.53	0.58	0.48	5	91
	3-Hour [b]	2.80	3.22	3.32	25	512
PM_{10}	Annual	0.006	0.009	0.008	1	15
	24-Hour	0.18	0.25	0.18	5	30
NO_2	Annual	0.009	0.012	0.010	1	25
CO	8-Hour	0.36	0.59	0.58	500	NA
	1-Hour	0.68	1.17	0.87	2000	NA
SAM	Annual	0.0018	0.0034	0.0028	NA	NA
	24-Hour	0.055	0.12	0.075	NA	NA
	3-Hour	0.19	0.32	0.28	NA	NA
HF	Annual	0.000007	0.000012	0.000010	NA	NA
	24-Hour	0.00021	0.00048	0.00030	NA	NA
Biscayne National Park						
SO_2	Annual	0.005	0.0088	0.0068	1	20
	24-Hour	0.15	0.34	0.21	5	91
	3-Hour [b]	0.82	1.40	1.28	25	512
PM_{10}	Annual	0.002	0.003	0.003	1	15
	24-Hour	0.055	0.117	0.075	5	30
NO_2	Annual	0.003	0.0051	0.0036	1	25
CO	8-Hour	1.74	3.12	2.41	500	NA
	1-Hour	2.89	6.82	3.78	2000	NA
SAM	Annual	0.0014	0.0029	0.0024	NA	NA
	24-Hour	0.03	0.09	0.05	NA	NA
	3-Hour	0.10	0.21	0.13	NA	NA
HF	Annual	0.000040	0.000079	0.000061	NA	NA
	24-Hour	0.00097	0.00257	0.00124	NA	NA

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model version 5.711a and three years of meteorological data, 2001 to 2003, develpd by VISTAS.

[b] Based on 3-hour average SO_2 emission rate of 0.065 lb/MMBtu.

TABLE 6-7 (FDEP-35)
SUMMARY OF THE MAXIMUM CONCENTRATIONS PREDICTED FOR FGPP
PROPOSED BOILERS ONLY

Pollutant, Averaging Time, and Rank		100% Load		70% Load		40% Load	
		Emission Rate [a] (lb/hr)	Predicted Concentration [c] (µg/m³)	Emission Rate [a] (lb/hr)	Predicted Concentration [c] (µg/m³)	Emission Rate [a] (lb/hr)	Predicted Concentration [c] (µg/m³)
SO_2							
Annual, Highest		696	0.55	487	0.50	278	0.42
24-Hour, Highest		696	5.16	487	4.82	278	3.87
3-Hour, Highest	d	1,131	24.1	792	21.9	452	17.8
PM_{10}							
Annual, Highest		313	0.25	219	0.23	125	0.19
24-Hour, Highest		313	2.32	219	2.17	125	1.74
NO_x							
Annual, Highest		870	0.69	609	0.63	348	0.53
CO							
8-Hour, Highest		2,680	42.1	1,876	41.6	1,072	34.8
1-Hour, Highest		2,680	103.5	1,876	87.1	1,072	70.0
SAM							
Annual, Highest		69.6	0.055	48.7	0.050	27.8	0.042
24-Hour, Highest		69.6	0.52	48.7	0.48	27.8	0.39
3-Hour, Highest		69.6	1.48	48.7	1.35	27.8	1.10
HF							
Annual, Highest		3.75	0.0030	2.63	0.0027	1.50	0.0023
24-Hour, Highest		3.75	0.028	2.63	0.026	1.50	0.021
Based on:	Year	Modeled Rate	Modeled Impact [c]	Modeled Rate	Modeled Impact [c]	Modeled Rate	Modeled Impact [c]
Annual, Highest	2001	7.937	0.00629	7.937	0.00805	7.937	0.0118
	2002	7.937	0.00532	7.937	0.00692	7.937	0.0102
	2003	7.937	0.00624	7.937	0.00822	7.937	0.0121
	2004	7.937	0.00552	7.937	0.00699	7.937	0.0102
	2005	7.937	0.00569	7.937	0.00743	7.937	0.0103
24-Hour, Highest	2001	7.937	0.0500	7.937	0.0693	7.937	0.102
	2002	7.937	0.0504	7.937	0.0616	7.937	0.084
	2003	7.937	0.0588	7.937	0.0786	7.937	0.110
	2004	7.937	0.0479	7.937	0.0647	7.937	0.086
	2005	7.937	0.0466	7.937	0.0662	7.937	0.099
8-Hour, Highest	2001	7.937	0.106	7.937	0.141	7.937	0.195
	2002	7.937	0.107	7.937	0.146	7.937	0.213
	2003	7.937	0.105	7.937	0.140	7.937	0.207
	2004	7.937	0.118	7.937	0.152	7.937	0.202
	2005	7.937	0.125	7.937	0.176	7.937	0.257
3-Hour, Highest	2001	7.937	0.148	7.937	0.198	7.937	0.283
	2002	7.937	0.148	7.937	0.205	7.937	0.290
	2003	7.937	0.149	7.937	0.201	7.937	0.291
	2004	7.937	0.169	7.937	0.199	7.937	0.287
	2005	7.937	0.157	7.937	0.219	7.937	0.313
1-Hour, Highest	2001	7.937	0.255	7.937	0.301	7.937	0.358
	2002	7.937	0.250	7.937	0.325	7.937	0.423
	2003	7.937	0.215	7.937	0.280	7.937	0.419
	2004	7.937	0.307	7.937	0.369	7.937	0.519
	2005	7.937	0.248	7.937	0.319	7.937	0.453

[a] Emission rate is for 2 units. PM_{10} emissions is only filterable PM.

[b] Predicted concentration is based on modeled concentration times the ratio of actual emission rate and modeled emission rate of 7.937 lb/hr (1 g/s).

[c] Modeled concentrations were predicted based on 7.937 lb/hr (1 g/s) emission rate for the 2 units with one combined stack and using AERMOD with five years of meteorological data from 2001 to 2005. The surface and upper air data were from the National Weather Service stations at Ft. Myers and Tampa, respectively.

[d] Based on 3-hour average SO_2 emission rate of 0.065 lb/MMBtu.

TABLE 6-8 (FDEP-35)
SUMMARY OF THE PSD CLASS II SIGNIFICANT IMPACT ANALYSIS FOR FGPP PROPOSED BOILERS AND PM MATERIAL HANDLING OPERATIONS

Pollutant, Averaging Time, and Rank	Maximum Predicted Concentration (μg/m³)			Significant Impact Level (μg/m³)
	100% Load	70% Load	40% Load	
PROPOSED BOILERS ONLY				
SO_2				
Annual, Highest	0.55	0.50	0.42	1
24-Hour, Highest	5.16	4.82	3.87	5
3-Hour, Highest [a]	24.1	21.9	17.8	25
PM_{10}				
Annual, Highest	0.25	0.23	0.19	1
24-Hour, Highest	2.32	2.17	1.74	5
NO_x				
Annual, Highest	0.69	0.63	0.53	1
CO				
8-Hour, Highest	42.1	41.6	34.8	500
1-Hour, Highest	103.5	87.1	70.0	2000
PROPOSED BOILERS AND PM MATERIAL HANDLING OPERATIONS				
PM_{10}				
Annual, Highest	0.80	NM	NM	1
24-Hour, Highest	6.89	NM	NM	5

Note: NM= not modeled.

[a] Based on 3-hour average SO_2 emission rate of 0.065 lb/MMBtu.

TABLE 6-9 (FDEP-35)
MAXIMUM CONCENTRATIONS PREDICTED FOR FGPP
AT THE PSD CLASS I AREAS OF THE EVERGLADES NP AND CHASSAHOWITZKA NWA
BASED ON EPA VERSION OF CALPUFF

Pollutant	Averaging Time	aximum Predicted Concentration (ug/m3			EPA Class I Significant Impact Levels (ug/m^3)	PSD Class I Increment (ug/m^3)
		2001	2002	2003		
Everglades NP						
SO_2	Annual	0.011	0.015	0.013	0.1	2
	24-Hour	0.42	0.39	0.36	0.2	5
	3-Hour [b]	2.61	2.08	2.30	1.0	25
PM_{10}	Annual	0.004	0.006	0.005	0.2	4
	24-Hour	0.15	0.18	0.13	0.3	8
NO_2	Annual	0.006	0.005	0.006	0.1	2.5
Chassahowitzka NWA						
SO_2	Annual	0.007	0.010	0.007	0.1	2
	24-Hour	0.16	0.19	0.13	0.2	5
	3-Hour [b]	1.00	1.13	0.76	1.0	25
PM_{10}	Annual	0.003	0.004	0.003	0.2	4
	24-Hour	0.068	0.079	0.059	0.3	8
NO_2	Annual	0.002	0.003	0.001	0.1	2.5

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model version 5.711a and 3 years of meteorological data, 2001 to 2003, developd by VISTAS.

[b] Based on 3-hour average SO_2 emission rate of 0.065 lb/MMBtu.

TABLE 6-12 (FDEP-35)
MAXIMUM SO_2 CONCENTRATIONS PREDICTED
FOR COMPARISON TO THE PSD CLASS I INCREMENTS AT THE
PSD CLASS I AREA OF THE EVERGLADES NP
BASED ON EPA VERSION OF CALPUFF

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m^3) [a]			PSD Class I Increment (ug/m^3)
		2001	2002	2003	
Everglades NP					
SO_2	24-Hour	3.67	3.00	4.58	5
	3-Hour [b]	8.05	8.42	9.60	25

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model version 5.711a and three years of meteorological data, 2001 to 2003, developd by VISTAS.

[b] Project modeled with 3-hour average SO_2 emission rate of 0.065 lb/MMBtu.

ATTACHMENT FDEP-36

REVISED VISIBILITY TABLE

TABLE 7-6 (FDEP-36)
MAXIMUM 24-HOUR AVERAGE VISIBILITY IMPAIRMENT PREDICTED FOR THE GLADES POWER PARK PROJECT
AT THE PSD CLASS I AREAS OF THE EVERGLADES NP AND CHASSAHOWITZKA NWA (CALPUFF VERSION 5.711a)

Meteorological Data	Parameter	Method 6 [c] (BART) 2001	Method 6 [c] (BART) 2002	Method 6 [c] (BART) 2003	Method 6 [c] (BART) MAX/ TOTAL	Method 6 (New IMPROVE Equation [a]) 2001	Method 6 (New IMPROVE Equation [a]) 2002	Method 6 (New IMPROVE Equation [a]) 2003	Method 6 (New IMPROVE Equation [a]) MAX/ TOTAL	Method 2 (New IMPROVE Equation [a]) 2001	Method 2 (New IMPROVE Equation [a]) 2002	Method 2 (New IMPROVE Equation [a]) 2003	Method 2 (New IMPROVE Equation [a]) MAX/ TOTAL	Method 2 [d] (PSD) 2001	Method 2 [d] (PSD) 2002	Method 2 [d] (PSD) 2003	Method 2 [d] (PSD) MAX/ TOTAL
Everglades NP																	
All Days	Maximum %	6.58	10.59	5.20	**10.59**	5.29	8.14	4.09	**8.14**	9.98	7.82	8.11	**9.98**	12.08	9.84	9.38	**12.08**
	# Days > 5%	1	4	3	**8**	1	3	0	**4**	1	6	3	**10**	1	11	6	**18**
	# Days > 10%	0	1	0	**1**	0	0	0	**0**	0	0	0	**0**	1	0	0	**1**
	8th Highest	3.38	4.09	3.96	**4.09**	2.66	3.18	3.07	**3.18**	3.18	4.39	3.62	**4.39**	4.12	5.79	4.43	**5.79**
Exclude Days	Maximum	NA	NA	NA	NA	NA	NA	NA	NA	3.88	7.82	8.11	**8.11**	4.96	9.84	9.38	**9.84**
	# Days > 5%	NA	NA	NA	NA	NA	NA	NA	NA	0	3	3	**6**	0	4	5	**9**
	# Days > 10%	NA	NA	NA	NA	NA	NA	NA	NA	0	0	0	**0**	0	0	0	**0**
Chassahowitzka NWA																	
All Days	Maximum	5.12	6.78	4.35	**6.78**	4.38	5.76	3.56	**5.76**	3.11	8.14	6.78	**8.14**	3.64	9.15	7.30	**9.15**
	# Days > 5%	1	4	0	**5**	0	4	0	**4**	0	4	1	**5**	0	5	1	**6**
	# Days > 10%	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
	8th Highest	2.08	3.25	1.85	**3.25**	1.80	2.78	1.67	**2.78**	1.88	4.13	2.32	**4.13**	2.28	4.63	2.58	**4.63**
Exclude Days	Maximum	NA	NA	NA	NA	NA	NA	NA	NA	3.11	5.32	3.78	**5.32**	3.64	6.06	4.23	**6.06**
	# Days > 5%	NA	NA	NA	NA	NA	NA	NA	NA	0	1	0	**1**	0	2	0	**2**
	# Days > 10%	NA	NA	NA	NA	NA	NA	NA	NA	0	0	0	**0**	0	0	0	**0**

[a] Background light extinction was re-calculated in the CALPOST-IMPROVE Processor (Version 2, dated October 14, 2006). The CALPOST-IMPROVE Processor uses the new IMPROVE equation developed by the IMPROVE Steering Committee.

[c] Background light extinction calculated using Method 6, which is based on Class I area specific monthly relative humidity adjustment factors.
Method 6 is the recommended method for addressing regional haze impacts for sources affected by the Best Available Retrofit Technology (BART) regulations.
The BART regulations also allows the 98th percentile impact or the 8th highest impact to be used to compare whether a source contributes to or causes visibility impairment.

[d] Background light extinction calculated using Method 2, which is based on hourly relative humidity observations. Maximum relative humidity cap used is 95%.
Method 2 is the recommended method for addressing regional haze impacts for projects undergoing review under the Prevention of Significant Deterioration (PSD) regulations.

ATTACHMENT FDEP-41

TABLE FDEP-41 – PM10 EMISSIONS AND SOURCE DIMENSIONS FOR MATERIAL HANDLING OPERATIONS USED IN THE AIR DISPERSION MODELING

TABLE FDEP-41
PM10 EMISSIONS AND SOURCE DIMENSIONS FOR MATERIAL HANDLING OPERATIONS USED IN THE AIR DISPERSION MODELING

Description	Units	Railcar unloading	Active Coal Pile	Inactive coal Pile	Limestone pile	Flyash	Bottom ash near boilers	Bottom ash-for sale	Gypsum	Byproduct Storage	Paved Road: Truck Traffic	Paved Road: Volume source parameter	Paved Road: Value	Paved Road: Basis
Source type		Area	Area	Area	Area	Area	Area	Area	Area	Area	Volume			
Height	ft	10	72	72	50	10	10	15	15	60	20	Modeled		10 1/2 height (middle of volume source)
	m	3.05	21.82	21.82	15.24	3.05	3.05	4.57	4.57	18.29	6.10	height =	3.05	
Length	ft	150	1140	1200	390	245	84	320	195	5100	11035.23	Initial vertical	9.30	height/2.15
	m	45.73	347.56	365.85	118.90	74.70	25.61	97.56	59.45	1554.88	3364.40	dimension (sz0) =	2.84	
Width	ft	50	150	800	165	50	22	100	170	3100	40	Initial horizontal	37.2	width 2.15 x 2 (approximate)
	m	15.24	45.73	243.90	50.30	15.24	6.71	30.49	51.83	945.12	12.20	dimension (sy0) =	11.3	(Every other area source)
Area	m2	697.13	15894.56	89232.60	5981.37	1138.65	171.77	2974.42	3081.11	1469519.33		No. volume sources=	135	
Total Emission rate	g/s/m2	3.43E-06	1.20E-06	2.43E-07	3.11E-06	2.66E-06	1.14E-05	3.95E-07	2.25E-06	3.11E-08			0.107 g/s	
		AREA15			AREA19	FASILO	BABLR1 & BABLR2	AREA27	AREA26					
	due to Wind erosion		2.91E-06	1.40E-07			(Emissions split)		5.40E-08	2.23E-08			0.000791 g/s volume src	
			AREA2WE	AREA9WE						BYPRODWE			BYPRD01-BYPRD135	
	Trucks		1.29E-06	1.03E-07					2.20E-06	8.85E-09				
			AREA2TR	AREA9TR						BYPRODTR				
Total Emission rate	lb/hr	0.047	0.530	0.172	0.242	0.024	0.016	0.009	0.055	0.363	0.347			

TRANSFER POINTS — PM10 Emissions (lb/hr) for Transfer Points and Fugitive Sources

Transfer point	Description	Railcar unloading	Active Coal Pile	Inactive coal Pile	Limestone pile	Flyash	Bottom ash near boilers
Coal Handling System- Dust Collection and Ventilation							
TP-1	Railcar unloading	0.047					
TP 5	Active coal stockout pile		0.1400				
TP 11	Inactive coal stockout pile			0.0000			
TP 26	Active coal stockout pile		0.0117				
TP 27	Active coal stockout pile		0.0117				
Limestone Handling System- Dust Collection and Ventilation							
TP 54	Bottom dumper unloading hopper				0.010		
TP 56	Active limestone stockout pile				0.010		
TP 61	Active limestone stockout pile				0.049		
TP-62	Active limestone stockout pile				0.049		
Fly Ash Handling System							
TP-71/TP 71A	Loadout to truck, silo area Unit 1					0.0120	
TP-69/TP 69A	Loadout to truck, silo area Unit 2					0.0120	
Bottom Ash Handling System							
TP 73	Storage bunker near boiler Unit 1						0.0075
TP-76	Storage bunker near boiler Unit 2						0.0075
Gypsum Handling System	0						

TABLE FDEP 41
PM10 EMISSIONS AND SOURCE DIMENSIONS FOR MATERIAL HANDLING OPERATIONS USED IN THE AIR DISPERSION MODELING

Description	Units	Railcar unloading	Active Coal Pile	Inactive Coal Pile	Limestone pile	Flyash	Bottom ash near boilers	Bottom ash for sale	Gypsum	Byproduct Storage	Paved Road: Truck Traffic	Paved Road: Volume source parameter	Paved Road: Value	Paved Road: Basis
TP-79	Transfer from dewatering bldg to conveyor- Unit 1								0.00895					
TP 81	Transfer from dewatering bldg to conveyor- Unit 2								0.00895					
TP 82	Transfer from pile to truck- Unit 1								0.00695					
TP 83	Transfer from pile to truck- Unit 2								0.00895					
TP 87	Transfer from pile to rail								0.01791					
FUGITIVES														
Coal Handling System- Dust Collection and Ventilation														
Wind erosion														
F-6 Fuel A	Active pile		0.12											
F-6 Pet Coke	Active pile		0.12											
F-6 Fuel B	Active pile		0.12											
F-14	Inactive pile			0.03										
F 13	Inactive pile			0.07										
Bulldozers														
F-12	Inactive pile			0.07										
F-28	Inactive pile			0.00										
Limestone Handling System- Dust Collection and Ventilation														
Wind erosion														
F-58	Active pile				0.01									
Bulldozers														
F 57	Active pile				0.05									
F-60	Active pile/ inactive pile				0.07									
Bottom Ash Handling System														
Wind erosion														
F-74	Storage bunker, near Unit 1						0.00024							
F-77	Storage bunker, near Unit 2						0.00024							
F 83	Storage pile							0.0016						
Front end Loaders														
F-75	Storage pile							0.0029						
F-76	Storage pile							0.0029						
Gypsum Handling System														
Wind erosion														
F-84	Storage pile								0.0007					
F-85	Storage pile								0.0007					
Byproduct Handling System														
Wind erosion														
F 91	Byproduct storage area									0.26				
Bulldozers and Truck, and Misc. Vi														
F 90	Byproduct storage area									0.10				
F 95	Byproducts and Vehicles										0.55			