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July 24, 2000

Mr. Clair Fancy
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Re: Florida Power Corporation
Hines Energy Complex
Power Block 2
Application for Prevention of Significant Deterioration Permit

Dear Mr. Fancy:

On behalf of Florida Power Corporation, I wish to submit to the Department Florida Power Corporation's (FPC) application for a Prevention of Significant Deterioration Permit for FPC's Hines Power Block 2. This new electrical power plant will be located at the Hines Energy Complex in Polk County, Florida.

This PSD permit application is being submitted in parallel with FPC's Supplemental Site Certification Application for this project. The Site Certification Application has been filed with the Department's Office of Siting Coordination on this same date along with the required Site Certification Application fee. Any fees for this PSD permit application will be covered by this site certification fee.

Enclosed are three copies of the PSD Permit Application and one copy of the entire Site Certification Application, as requested by Mr. Al Linero.

Should you or your staff have any questions concerning this PSD Application, please contact Mike Kennedy of FPC (727-826-4334). FPC looks forward to working with the Department in the successful permitting of this project.

Sincerely,

Douglas S. Roberts

Encls.

cc: Hamilton S. Oven
Scott A. Goorland, Esq.
W. Jeffrey Pardue (FPC)

Florida Power
CORPORATION

W. Jeffrey Pardue, C.E.P.
Director
Environmental Services Department

July 21, 2000

Hamilton Oven, P.E., Administrator
Office of Siting Coordination
Department of Environmental Protection
2699 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Oven:

RE: Florida Power Corporation
Hines Energy Complex
Power Block 2
Supplemental Site Certification Application to PA 92-33

Florida Power Corporation (FPC) is pleased to submit to the Department FPC's Supplemental Site Certification Application for Hines Power Block 2 to be located at the Hines Energy Complex in Polk County.

Pursuant to Section 403.517, F.S., of the Florida Electrical Power Plant Siting Act, Chapter 403, Part II, F.S., FPC is seeking supplemental certification for the construction and operation of Power Block 2. This addition is a 530 MW (nominal) combined cycle facility fired by natural gas with distillate oil as a back-up fuel. Ultimate site capacity of 3000 MW was approved for the Hines Energy Complex in 1994 (DEP Case No. PA 92-33). The Conditions of Certification were subsequently modified in December 1995, August and December 1997. In March 2000, a post-certification Amendment was filed which is still under review. FPC anticipates seeking a separate modification for a new water resource project for the Hines Energy Complex site known as the Aquifer Recharge and Recovery Project (ARRP) in the near future. This modification will be independent of the supplemental site certification application.

Enclosed is Check #2074723, payable to the Department in the amount of $50,00.00, pursuant to Rule 62-17.293(1)(d), F.A.C., for the supplemental certification of a combined cycle facility fueled by gas or distillate oil.

The application for supplemental certification addresses the environmental and socioeconomic impacts and benefits of Hines Power Block 2 by providing information in accordance with the Department's "Instruction Guide for Certification Applications: Electrical Power Plant Site, Associated Facilities, and Transmission Lines", DER Form 17-1.211(1), F.A.C. Since the Hines Energy Complex site has been previously certified for an ultimate site capacity of 3,000 MW, this application focuses on the specific impacts and benefits associated with the construction and operation of Power Block 2 on this site. The Siting Board has previously determined that

FPC's Hines Energy Complex site is consistent and in compliance with the land use plans and zoning regulations of Polk County. Accordingly, a separate compilation on land use and zoning approvals is not included with this application.

FPC looks forward to working with the Department and the other agencies participating in the certification process. Should you, your staff, or any agency representatives have any questions concerning this application or FPC's project, please do not hesitate to contact either Manitia Moultrie (727/826-4267) or me at (727/826-4301).

Sincerely,

W. Jeffrey Pardue
Director
Environmental Services Department

Enclosure

PREFACE

Florida Power Corporation (FPC) is an investor-owned utility, which supplies electricity to about 4.4 million people in 32 Florida counties. FPC, headquartered in St. Petersburg, Florida, has served Florida for 100 years. FPC's mission is to provide safe, reliable, environmentally sound and competitively-priced energy to our customers.

In February, 1992, the Public Service Commission (PSC) determined the need existed for FPC to develop natural gas-fired combined-cycle generating capacity at FPC's Hines Energy Complex, an approximate 8,000-acre site in southwest Polk County. Moreover, the PSC found the need existed for the electricity to be provided by an initial 470 MW (nominal) power plant at that site.

Also in 1992, the Polk County Board of County Commissioners found the Hines Energy Complex site (formerly referred to by FPC as the "Polk County site") to be consistent and in compliance with the County's land use plans and zoning ordinances. The Siting Board entered a final order in February, 1993, confirming that the planned 3000 MW of generating capacity for the Hines Energy Complex is consistent and in compliance with the land use plans and zoning requirements of Polk County for that site. Since the site boundaries will not be increased by this application, land use and zoning issues are not at issue in this supplemental application, as provided by section 403.517(3), Florida Statutes.

In 1994, the Governor and Cabinet, sitting as the Siting Board, granted certification to FPC, to construct and operate Power Block 1 and for 3000 megawatts (MW) of ultimate site capacity at the Hines Energy Complex. (A copy of the 1994 Final Order Approving Certification, which includes the Conditions of Certification, is in Appendix 10.4.1. Appendix 10.4.2, 10.4.3, 10.4.4 and 10.4.12 contain the Final Orders Modifying Conditions of Certification rendered in balance of siting criteria including location near power needs, minimal environmental impact, and cost. Development of the Hines Energy Complex site takes advantage of utilizing an already disturbed phosphate mine site for current and future power needs. Many of the environmental impacts associated with power development on new sites are not at issue here, since the site has been previously altered and disturbed by prior mining activity. The site has the further advantages of being close to FPC's load center and being served by electric transmission and rail and highway transportation facilities, which minimizes ancillary impacts.

In 1999, FPC began operation of Power Block 1 at the Hines Energy Complex. By this application, FPC is seeking supplemental certification for the construction and operation of Power Block 2, an additional 530 MW (nominal) of generation, under the Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes (F.S.).

To the extent the Siting Board's previous ultimate site capacity determination has already addressed the ultimate impacts and benefits of the development of 3000 MW of electrical generating capacity at the Hines Energy Complex site, they are not addressed in detail in this application. Instead, each area of potential impact and benefit addressed in the 1994 Certification is explained for informational purposes. Those areas of impact and benefit which were not addressed in the 1994 Certification due to a lack of detailed knowledge of the design of future generating units are addressed consistent with the requirements of DEP Form 17-1.211(1) for proposed Power Block 2.

This Supplemental Certification Application (SCA) is being filed pursuant to the requirements of the PPSA and Chapter 62-17, F.A.C. The SCA addresses the environmental and socioeconomic aspects of the additional generating unit at the Hines Energy Complex by presenting information on the existing natural and

CHAPTER 1

NEED FOR POWER AND PROPOSED FACILITIES

TABLE OF CONTENTS

1.1 NEED SUMMARY

By the petition filed in August 1991 in Docket No. 910759-EI, Florida Power Corporation (Florida Power or FPC) requested that the Florida Public Service Commission (PSC, or the Commission) determine the need for four 235 MW, natural gas-fired combined-cycle (CC) generating units at FPC's Hines Energy Complex in Polk County, which were then referred to as Polk County Units 1 through 4. By Order No. 25805, issued February 25, 1992, the Commission approved the need for Polk County Units 1 and 2 (now combined into Hines Power Block 1), but deferred a decision on Units 3 and 4 (combined into Hines Power Block 2), because of several uncertainties regarding the timing of the need for Power Block 2. The order allowed Florida Power to return to the Commission when the timing of additional needs beyond that satisfied by the approved Units 1 and 2 became clearer.

On December 8, 1999, FPC announced plans to build the Hines Power Block 2, a 530 MW (nominal) natural gas-fired combined-cycle generating unit. The unit, which has an in-service date of November 2003, will insure the continuing adequacy of FPC's generating capacity. Further, the Florida Public Service Commission (FPSC) recently gave unanimous approval to increase from 15 percent to 20 percent the level of "reserve" electric generating capacity that utilities operating in the state are required to have (reserve margin) beginning in 2004. Hines Power Block 2 will contribute toward meeting that 20 percent reserve margin in FPC's service area. The addition of Power Block 2 will also improve the balance of total capacity resources between Company-owned generation and purchased power. As a result, in mid-July, 2000, FPC will initiate the required regulatory process by petitioning the Commission for the determination of need to construct Hines Power Block 2 at the Hines Energy Complex.

Prior to filing its petition for a need determination for Hines Power Block 2, in order to be sure FPC's customers' best interests are being served, FPC sought outside bids to provide the additional capacity, and evaluated all viable options to supply the incremental power needed. On January 26, 2000, FPC publicly solicited bids or proposals from qualified bidders, which were then compared with the Hines Power Block 2 option on numerous factors, including location, price, dispatchability, flexibility and reliability of the power offered as well as environmental considerations. The bids received were carefully evaluated on these factors. Based upon that detailed evaluation, the Hines Power Block 2 option has proven to be the most cost-effective option to supply the electricity needed in November 2003.

In addition to satisfying FPC's need for additional capacity, the unique characteristics of Hines Power Block 2 provide Florida Power with the means to address this need in the most expeditious and cost-effective manner possible. As an initial matter, it should be noted that Hines Power Block 2 had been originally scheduled for completion in the 1999-2000 time frame when submitted to the Commission for need approval in 1991. As a result, the unit has the advantage of considerable advance planning and design, as well as the scheduling and cost advantages of previously-secured equipment and construction options. Even more important to the unit's ability to be placed in service quickly is the availability of an existing plant site, selected because of its minimal environmental impact, with an infrastructure capable of accommodating Hines Power Block 2 with only minor additions. The infrastructure already in place at the Hines Energy Complex includes extensive site development (access roads, cooling pond, water treatment facilities, transmission facilities, etc.) that will support the two-unit operations at the site.

Based on the cost, scheduling, site, environmental, and utility control advantages of the proposed new plant, FPC will soon undertake the appropriate regulatory steps for approval of Power Block 2 by filing a petition for determination of need.

1.2 PSC ORDER ON NEED

As stated in Section 1.1, the required PSC regulatory process will commence in mid-July, 2000. FPC expects to complete the PSC approval process for building Power Block 2 by January 2001.

A copy of FPC's Petition for Need Determination will be submitted to the Department of Environmental Protection and other agency recipients of this SCA when the Petition is filed with the PSC. FPC expects to file the Petition with the PSC in mid-July, 2000. Upon receipt of the PSC final order determining the need for Hines Power Block 2, copies will be filed with the Division of Administrative Hearings' Administrative Law Judge assigned to the certification proceeding for Power Block 2 and distributed to the agencies receiving this SCA.

1.3 SITE SELECTION PROCESS

In January 1989, recognizing that its forecasts indicated a need for additional generation capacity, FPC began the comprehensive process of locating a suitable site for a large new generation facility which resulted in the selection and initial development of the Hines Energy Site in Polk County, Florida. A large site is desirable in order to maximize the economies of development and long-term operation.

Specifically, the objective of the site selection program was to determine a primary and alternate site that would be:

- Multi-unit and clean coal capable
- Technology- and fuel-flexible
- Cost effective
- Fully compatible with FPC's commitment to environmental protection
- In compliance with all government regulations
- Consistent with state and local land use policies

FPC used a systematic site selection approach to ensure that all of the above concerns were fully addressed. The process involved the following five phases, each with a specific objective:

Phase I

The first phase, **Area Screening**, began by screening the entire state of Florida. This phase screened out or eliminated areas that were either environmentally protected or clearly unsuited for development of the proposed facility. Phase I concluded by defining 172 large potential areas suitable for the project.

Phase II

The next phase, **Area Ranking**, ranked the 172 potential areas using criteria that evaluated environmental, socioeconomic and engineering issues. Phase II concluded by defining the top 60 candidate areas.

Phase III

The third phase, **Site Identification**, identified specific sites among the 60 candidate areas by conducting another screening process on a more refined geographic basis. Phase III concluded by defining 22 potential "semifinalist" sites.

Phase IV

The fourth phase, **Site Ranking**, ranked the 22 semifinalist sites using advanced criteria that further evaluated environmental, socioeconomic and engineering issues. Phase IV concluded by defining the top five candidate sites.

Phase V

The final phase, **Site Selection**, confirmed the Phase IV site ranking with additional field data and/or analytical evaluation. Phase V concluded in October 1990 by identifying the preferred and alternate sites.

Throughout this lengthy and careful process, FPC was assisted by an independent group of environmentalists, educators, and community leaders. This Environmental Advisory Group provided advice on matters of public concern, with their major function being to review plans for each of the five phases of the siting process and suggest changes in the evaluation process. FPC also systematically elicited the preferences of this independent panel to assist in the development of ranking criteria used in the evaluation process. In addition to the input received from the Environmental Advisory Group, FPC consulted with various regulatory agencies at specific points in the process to obtain their perspective on siting criteria.

As a result of this extensive statewide search, FPC selected a location in Polk County as the primary site of its next generating units and an alternative site in Hardee County. Both locations met FPC's goal for a large site capable of handling staged development of various generation and fuel options. The 1994 Certification found that the Hines Energy Complex site is capable of supporting 3,000 MW of total generation.

1.4 TECHNOLOGY SELECTION

1.4.1 Generation Alternatives

FPC's need for additional generation is based upon specific system reliability criteria. A system optimization tool was used to generate a significant number of potential generation expansion alternatives which would satisfy FPC's system reliability criteria. These alternatives were examined and compared to quantify the costs and benefits of a variety of generation expansion technologies, plant sizes, and construction options.

In developing these expansion alternatives, FPC considered four major constraints. First, the technologies used in alternative plans must meet FPC's criteria for technical feasibility, reliability, and potential cost effectiveness. Second, the alternative plans must result in a system that meets or exceeds FPC's reliability criteria during each year of the plan. Third, the alternative plan must be consistent with FPC's commitment to environmental protection. Finally, the alternative must represent a plan that is well integrated with the present operation and configuration of the FPC system.

The generation alternatives that were evaluated included combinations of pulverized coal (PC) units, combustion turbines (CTs), combined cycle (CCs), fluidized bed, gasification plants, and existing plant repowering operations. Each of the alternatives included generation units modeled to come into service between 2001 and 2008.

FPC's economic evaluation of these alternatives included cumulative present worth revenue requirement comparisons. In addition, FPC evaluated several uncertainties for each alternative based on the high, medium and low demand and energy forecasts; and the high, medium, and low fuel forecasts. The final result of this decision analysis was a comparison of cumulative present worth revenue requirements of each of the alternatives on FPC's system.

A second combined cycle unit at the Hines Energy Complex emerged from all of these calculations as the most cost-effective alternative. In other words, these units are expected to lead to the lowest cost of service and the lowest rates, when viewed on a present value or present worth basis. The units also do not pose any unusual risks in the event that some of the key planning assumptions used by FPC turn out to vary according to their expected probability distribution.

1.4.2 Combined Cycle Design

The technology selected for the initial phases of the Hines Energy Complex is based on the use of modern, high efficiency gas-fired CTs and steam turbines (STs) configured in a "combined cycle" (CC). Generating stations are referred to as CC when they have two sequential electrical generating stages. The first stage of a CC plant is a CT, much like a utility peaking plant. In the second stage of the process, the hot gas from the CT is passed through a heat recovery steam generator (HRSG), where steam is produced and directed to the ST. The CT and ST can be designed to drive individual electrical generators or to drive a single generator.

The approximate average annual electrical output measured in MW for these CCs is expressed as the "nominal" output. Power Block 1 has a nominal output of 470 MW. Power Block 2 will have a nominal output of 530 MW. The actual output of either unit can vary seasonally above and below the nominal output.

In sum, because CC plants make excellent use of the energy in their input fuel, they have an extremely low heat rate. The modern CC power plant is one of the most efficient power cycles available today.

2.3.7 Meteorology and Ambient Air Quality

2.3.7.1 Meteorology

REGIONAL CLIMATE

The climate in central Florida is classified as subtropical with maritime influences from both the Atlantic Ocean and the Gulf of Mexico. Summers are long, warm, and relatively humid, while winters are mild because of the latitude and the warming influence of the Gulf Stream. Coastal locations average slightly warmer in winter and cooler in summer than do the inland areas. The summer heat is tempered by sea breezes along the coasts and by frequent afternoon or early evening thunderstorms in all areas. Thunderstorms, which on the average, occur on about one-half of the days in the summer, frequently are accompanied by a temperature drop of as much as 10 to 20 degrees. They cause high winds, heavy rain, occasional hail, and frequent lightning. Tornadoes that reach the surface are a rare occurrence in this part of the state, and very destructive tornadoes are almost nonexistent. Tornadoes are most likely to occur during seasonal changes when cool, dry air and warm, moist air clash.

Hurricanes are tropical cyclones in which winds reach speeds of 74 mph or more and blow in a large spiral around a relatively calm center. Near the center (eye), hurricane winds may gust to more than 200 mph, and the storm dominates the ocean surface and lower atmosphere over tens of thousands of square miles. The fastest non-gust wind speed (fastest mile of wind) recorded at Tampa was 84 mph, and the fastest 5-minute average was 75 mph. These both occurred with the passage of the Labor Day hurricane of September 3 to 5, 1935 (NOAA, 1977).

Gentle breezes occur almost daily in all areas. Because most of the large-scale wind patterns affecting Florida have passed over water surfaces, hot drying winds seldom occur. High local winds of short duration occur occasionally in connection with thunderstorms in summer and with cold fronts moving across the state in other seasons.

Climatological data for the site area are available from the weather service offices at Tampa (47 miles northwest), Orlando (62 miles northeast), and Lakeland (21 miles north-northwest). Based on discussions with and recommendations from FDEP in association with the 1992 SCA, observations from the National Weather Service (NWS) station at Tampa International Airport are used as representative data for the site. The Local Climatological Data summary, from which the climatological data presented in this section are taken, is included as Appendix 10.5.3.

The humidity in Florida is generally high. Inland areas with greater temperature extremes experience slightly lower relative humidity, especially during times of hot weather. On the average, variations in relative humidity from one place to another are small; humidities range from about 50 to 65 percent during the afternoon hours to about 80 to 90 percent during the night and early morning hours.

Heavy fogs are usually confined to the night and early morning hours in the late fall, winter, and early spring months. On the average, they occur on about 21 days a year at Tampa. These fogs usually dissipate or thin soon after sunrise; heavy daytime fog is seldom observed in Florida.

The following temperature statistics are based on data collected from the Tampa station for the period-of-record 1961 through 1990, which is the latest 30-year period currently available that is used to describe normal averages by the NWS. These data are summarized in Appendix 10.5.3. The mean annual temperature is approximately 72°F with monthly temperatures varying from a maximum of 90°F to a minimum of 50°F. Record extreme temperatures range from a low of 18°F to a record high of 99°F. Although the sun's elevation is nearly zenith during the summertime, temperatures do not exceed 100°F. The reason can be attributed to the high relative humidities with subsequent cloud cover formation and the resultant abundant convective-type precipitation.

For rainfall data, the nearest station that measures representative data for the plant site is Bartow. Average annual rainfall at Bartow is 53.43 inches. Lowest monthly average rainfall occurs in December with 2.00 inches, and highest monthly average rainfall occurs in July with 8.42 inches.

For the NWS station at Tampa, normal annual rainfall is approximately 44 inches. Typically, the rainy season begins in June and ends in September. Most of the summer rainfall is derived from local showers or thunderstorms. The highest normal monthly rainfall is approximately 7.6 inches and occurs in August. April is the driest month, with an average of approximately 1.2 inches of precipitation. The maximum rainfall in one day was 12.11 inches and occurred in July 1960. Record monthly precipitation also occurred in July 1960, when 20.59 inches of rain were recorded.

March has the highest mean monthly wind speed of 9.5 mph. The lowest mean monthly wind speed of 7.0 mph is usually encountered in August. An easterly prevailing wind direction is evident during most of the year. The annual average wind speed is 8.3 mph. The predominant wind direction during the 1987 to 1991 time period was from the east-northeast, which occurred approximately 12 percent of the time. Wind directions from the east, northeast, and east-southeast each occurred more than 8 percent of the time. A wind rose for Tampa is presented in Figure 2.3.7-1.

DISPERSION METEOROLOGY

STABILITY. Atmospheric stability in conjunction with general wind patterns and mixing height determines the potential of the atmosphere to disperse airborne pollutants. Atmospheric stability conditions are typically categorized as unstable, neutral, or stable. An unstable atmosphere is one in which rapid diffusion takes place in both the horizontal and vertical directions. In terms of temperature change with height, an unstable atmosphere is characterized by a sharp decrease in temperature with height. Neutral conditions, which are characterized by moderate decreases of temperature with height, are common in the atmosphere and are associated with moderate diffusion rates. A stable atmosphere is characterized by a slight decrease (less than 1°C per 100 meters), or even an increase in temperature with height, and greatly reduced diffusion rates in comparison with unstable or neutral atmospheric conditions.

The stability classifications discussed in this section are based on the Turner (1970) classification scheme, which assigns a stability on the basis of surface wind speed, cloud cover, and solar insolation.

During the summer months, unstable atmospheric conditions occur nearly 40 percent of the time due to strong insolation, whereas unstable conditions occur only 18 percent of the time in the winter months. Neutral conditions occur most frequently during the winter months due to the higher wind speeds and lower temperatures in this season. The occurrence of stable conditions is nearly uniform throughout the year, with a maximum occurrence of approximately 47 percent in the fall.

MIXING HEIGHT. An important parameter which describes the regional dispersion capability of the atmosphere is mixing height. Mixing height is simply the vertical extent of the surface layer within which relatively vigorous mixing of pollutants takes place.

Holzworth (1972) has compiled statistical summaries for mixing height at various locations throughout the United States based on twice daily radiosonde measurements. The abundance of moisture from the ocean around southern Florida creates high humidities and low-level cloudiness that absorb heat and generally prevent the mixing height from subsiding below 500 meters. Because mixing heights are dependent upon surface temperatures, afternoon levels reach above 1,400 meters under intense solar insolation. Lesser diurnal mixing height fluctuations occur at coastal stations in Florida, as compared to inland locations, due primarily to moderating effects of the ocean.

The Tampa upper air station has been considered regionally representative of the site by FDEP in previous applications, including the 1992 SCA. The Tampa data indicate that the site area experiences mixing heights that are typical of or higher than large areas of the eastern half of the United States. Thus, the site area experiences better than average dispersion conditions. The Tampa upper air data for 1987 through 1991 were included as part of the meteorological data input to the dispersion modeling evaluation of the Power Block 2 air quality impacts discussed in Sections 6 and 7 of the PSD permit application.

2.3.7.2 Ambient Air Quality

REGIONAL AIR QUALITY

The Hines Energy Complex is located in an area that FDEP currently classifies as attainment for all criteria pollutants. It is designated as Class II from a Prevention of Significant Deterioration (PSD) standpoint. The nearest Class I area is the Chassahowitzka National Wilderness Area, located approximately 118 km to the northwest.

Ambient air monitoring data are available that can be used to characterize the existing conditions in the vicinity of the site. FDEP data from these monitors for 1997 are summarized in Table 2.3.7-1. The nearest FDEP PM_{10} data are from Mulberry. These data show that the maximum PM_{10} concentrations are well below National and Florida Ambient Air Quality Standards (AAQS). In addition, historical Total Suspended Particulate (TSP) data for Polk County (1992 SCA) indicate that existing PM_{10} concentrations would also be well below the AAQS.

SO_2 concentrations have been measured by FDEP at Mulberry and Nichols. FDEP data from 1999 show existing SO_2 concentrations at those nearby locations to be well below the AAQS.

Ozone (O_3) data are collected at two locations in Lakeland. FDEP data from 1999 show existing O_3 concentrations in Lakeland are within the AAQS.

Ambient data for nitrogen oxides (NO_x), carbon monoxide (CO), and lead (Pb) have been collected by FDEP only in the Tampa and Sarasota metropolitan areas. Given the rural nature of the site, existing concentrations of these pollutants, which are usually associated more closely with urban environments (since they are emitted primarily by mobile sources), should be well below the applicable standards at the plant site.

2.3.7.4 References

CFR (U.S. Code of Federal Regulations). Title 40, Section 52.21, Prevention of Significant Deterioration of Air Quality.

EPA (U.S. Environmental Protection Agency). 1987. Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD). EPA-450/4-87-007. Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina.

Holzworth, C. C. 1972. Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States. U.S. Environmental Protection Agency. AP-101, January, 1972.

NOAA (National Oceanic and Atmospheric Administration). 1998. Local Climatological Data Annual Summary with Comparative Data - Tampa, Florida. National Climatic Center. Asheville, North Carolina.

Turner, D. B. 1970. Workbook of Atmospheric Dispersion Estimates. U.S. Environmental Protection Agency. Research Triangle Park, North Carolina.

Florida Power Corporation. 1992. Polk County Site. Site Certification Application.

TABLE 2.3.7-1

REGIONAL 1999 AMBIENT AIR QUALITY DATA

CONCENTRATION (µg/m³)

POLLUTANT	LOCATION	SITE #	3-HOUR HIGH	3-HOUR 2ND HIGH	24-HOUR HIGH	24-HOUR 2ND HIGH	ANNUAL ARITHMETIC MEAN
SO_2	MULBERRY	121050010	183	136	50	50	18
	NICHOLS	121052006	149	120	47	34	10

POLLUTANT	LOCATION	SITE #	1-HOUR HIGH	1-HOUR 2ND HIGH
O_3	LAKELAND	121056005	194	180
	LAKELAND	121056006	202	198
	TAMPA	120570081	235	228
	TAMPA	120571035	233	208
	TAMPA	120571065	251	220
	PLANT CITY	120574004	228	192

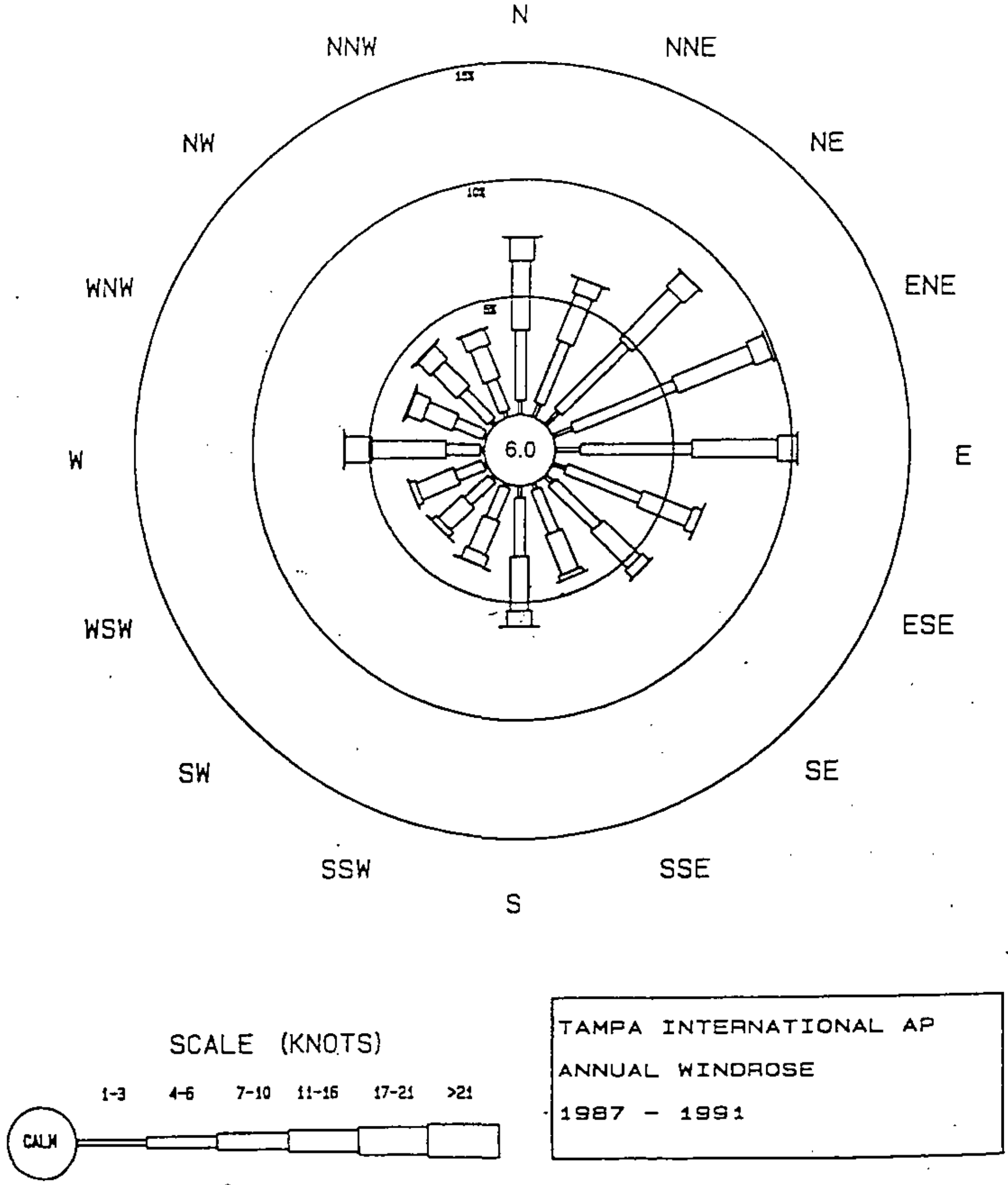
POLLUTANT	LOCATION	SITE #	ANNUAL ARITHMETIC MEAN
NO_2	TAMPA	120570081	18
	TAMPA	120571065	20
	ST. PETERSBURG	121030018	12

POLLUTANT	LOCATION	SITE #	1-HOUR HIGH	1-HOUR 2ND HIGH	8-HOUR HIGH	8-HOUR 2ND HIGH
CO	TAMPA	120570063	10,300	9,730	6,070	5,380
	TAMPA	120571035	4,690	3,200	2,520	1,830
	TAMPA	120571070	6,980	6,640	4,460	3,780
	PLANT CITY	120574004	4,120	2,750	1,720	1,490

POLLUTANT	LOCATION	SITE #	24-HOUR HIGH	24-HOUR 2ND HIGH	ANNUAL ARITHMETIC MEAN
PM_{10}	MULBERRY	121050010	45	42	22
	MULBERRY	121052006	50	50	22

POLLUTANT	LOCATION	SITE #	QUARTERLY ARITHMETIC AVERAGE JAN/MAR	APR/JUN	JUL/SEPT	OCT/DEC
Pb	TAMPA	120571066	0.42	0.41	0.42	1.02
	TAMPA	120571073	0.27	0.17	0.13	0.07
	TAMPA	120571074	0.03	0.08	0.03	0.01

Source: FDEP, 1999



Florida Power CORPORATION

Hines Energy Complex

FIGURE 2.3.7 -1
TAMPA WIND ROSE

3.4 AIR EMISSIONS AND CONTROLS

Power Block 2 will consist of an additional two natural gas-fired CC units capable of producing approximately 530 MW (nominal). Specific information about these units is presented in the Prevention of Significant Deterioration (PSD) application included as Appendix 10.1.5.

The remainder of this section will address the air emissions and controls for the proposed development.

3.4.1 Air Emission Types and Sources

Following is a description of the sources and types of air emissions at the Hines Energy Complex.

3.4.1.1 Sources

The primary sources of air emissions for this proposed development are the two Siemens Westinghouse combustion turbine (CT) units. The best available control technology (BACT) for these sources is presented in Section 3.4.3.

3.4.1.2 Emissions

Estimated maximum emissions from each of the air emission point sources noted in Section 3.4.1.1 are tabulated in Table 3.4.1-1. The estimated emissions represent full load operating conditions and are not inclusive of background ambient concentrations introduced into the particular processes. It is anticipated that higher emission rates will occur for short periods of time when a unit is started from a cold start or possibly during a malfunction. A comparison of the significant emission rate thresholds given in the Table demonstrates that the project is subject to

PSD BACT review for nitrogen oxides (NO_x), sulfur dioxide (SO_2), sulfuric acid mist (SAM), carbon monoxide (CO), particulate matter (TSP and PM_{10}) and volatile organic compounds (VOCs).

3.4.1.3 Emissions Inventory

For source specific emissions, DEP Form 62-210.900(1), "Application For Air Permit - Long Form", has been completed for Power Block 2, a copy of which is included in Appendix 10.1.5. These emissions are based on a 100 percent capacity factor at full load.

3.4.2 Air Emission Controls

The proposed control technologies and associated emission rates for the regulated pollutants emitted from each of the primary sources on the site are tabulated in Table 3.4.2-1. A detailed BACT analysis, including an economic evaluation, was performed and is presented in Appendix 10.1.5, Section 4.0.

3.4.3 Best Available Control Technology (BACT)

This BACT discussion provides a preliminary "worst case" scenario of generation alternatives and the corresponding analysis of the air quality control alternatives for controlling pollutant emissions from the Hines Energy Complex.

Under the federal Clean Air Act (CAA), BACT represents an emission limitation based on the maximum degree of pollutant reduction determined on a case-by-case basis considering technical, economic, energy, and environmental considerations. However, BACT cannot be less stringent than the emission limits established by the applicable New Source Performance Standards (NSPS) for stationary sources.

This BACT analysis follows the general requirements of the EPA's draft "top down" BACT guidance document, which requires that the BACT analysis start by assuming the use of the most stringent control alternative. Other less efficient emission control technologies are evaluated if this most stringent alternative is determined to be technologically infeasible or unreasonable considering economic, energy, and environmental factors.

As discussed in Section 3.4.1, the following regulated pollutants exceed the PSD significant emission rate thresholds and are, therefore, subject to PSD review:

- Carbon Monoxide (CO)
- Nitrogen oxides (NO_x)
- Sulfur dioxide (SO_2)
- Particulate (TSP and PM_{10})
- Volatile organic compounds (VOC)
- Sulfuric acid mist (SAM)

Consequently, the BACT analysis for Power Block 2 presented in Appendix 10.1.5, Section 4.0, addresses the control of emissions of these pollutants. Also included are discussions of the effects of the BACT systems selected on the emissions of other regulated pollutants.

3.4.4 Design Data for Control Equipment

Control equipment design information is included as part of the BACT analyses discussed in Section 3.4.3. Pollutant emission rates and specific control technologies are summarized in Table 3.4.2-1.

The CC units will be designed to minimize NO_x formation by the use of combustion controls, low NO_x burners and selective catalytic reduction (SCR). Water will be injected into the combustion zones to lower combustion temperatures and limit NO_x formation during oil firing. The annual emissions of other regulated pollutants which might be emitted from the CC units in quantities subject to PSD review (SO_2, CO, particulate matter [TSP/PM_{10}], VOCs and SAM) will be controlled by limiting the amount of fuel oil burned annually, limiting the sulfur content of the fuel, efficient operation of the CC facility, and utilizing good combustion control of the units.

3.4.5 Design Philosophy

Air quality control system designs are determined based on conservative design parameters. The parameters are developed to ensure that the air quality control system performance meets or exceeds the requirements specified by state and federal regulatory NSPS. Critical equipment that may affect the overall system reliability will have spare units in place to assure continuous operation. In addition, the application of top-down BACT (i.e., the evaluation of technical/engineering, economic, and environmental considerations) is used to determine appropriate air emission control technologies. The BACT analysis, discussed in Section 3.4.3, results in the selection of the best air quality control system for the particular site.

TABLE 3.4.1-1

MAXIMUM POTENTIAL ANNUAL EMISSIONS (530 MW) AND PSD SIGNIFICANCE VALUES

Pollutant	Emissions (TPY) *	PSD Significant Emission Rate (TPY)	PSD Review Required (Yes/No)
Carbon Monoxide	744	100	Yes
Nitrogen Oxides	289	40	Yes
Sulfur Dioxide	137	40	Yes
Particulate Matter (PM_{10})	121	15	Yes
Total Suspended Particulates (TSP)	121	25	Yes
Volatile Organic Compounds	57	40	Yes
Lead	0.02	0.6	No
Sulfuric Acid Mist (SAM)	21	7	Yes

* TPY = Tons per year for the proposed Power Block 2 project.

Basis:

			Annual Hours of Operation / CT	
	Load	Ambient Temp.	Gas	Oil
NO_x	100%	59° F	7,760	1,000
SO_2	100%	59° F	7,760	1,000
TSP/PM_{10}	100%	59° F	7,760	1,000
Lead	100%	59° F	7,760	1,000
SAM	100%	59° F	7,760	1,000
CO	100%	59° F	4,760	1,000
	60%	59° F	3,000	--
VOC	100%	59° F	4,760	1,000
	60%	59° F	3,000	--

Source: Golder Associates, 2000.

Table 3.4.2-1.

Summary of Proposed BACT Control Technologies and Emission Limits

Hines Energy Complex Power Block 2

(Siemens Westinghouse 501FD CTs)

Pollutant	Fuel	Load (%)	Control Technology	Proposed BACT Emission Limits[a] Concentration (ppm)	Mass (lb/hr)
TSP/PM_{10}	Gas	All	Natural gas and limited use of low-sulfur fuel oil	10%[b]	NA
	Oil	All	Efficient and complete combustion	20%[b]	NA
CO	Gas	100-65	Efficient and complete combustion	10	42
	Oil	100-65	Efficient and complete combustion	30	106
	Gas	60	Efficient and complete combustion	50	146
VOC	Gas	100	Efficient and complete combustion	1.8	4.4
	Oil	100-65	Efficient and complete combustion	10	21
	Gas	80-60	Efficient and complete combustion	3.0	7.5
NO_x	Gas	100-60	Use of dry low-NO_x burners and SCR	3.5[c]	23
	Oil	100-60	Water injection and SCR	15[c]	114
SO_2/SAM	Gas/Oil	All	Natural gas and limited use of low-sulfur fuel oil	NA	NA

a NO_x is ppmvd at 15% O_2 gas and oil; CO is ppmvd at 15% O_2 for gas and ppmvd for oil; VOC is ppmvd at 15% O_2 for gas and ppmvw for oil. Max emissions at 59°F compressor inlet.

b Percent opacity, a surrogate for TSP/PM_{10} limits.

c Based on a 24-hr block (7:00 a.m. to 7:00 a.m.) weighted average based on load as measured by CEMS.

Source: Golder Associates, 2000.

4.5 AIR IMPACT

4.5.1 Air Quality Impacts

During the construction period, unavoidable air pollutant emissions are likely to occur from various construction-related activities. The most prevalent construction emissions are fugitive dust. However, minor emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter, and volatile organic compounds (VOCs) are also likely during construction. Emissions of these pollutants generally are minimized through standard control measures.

4.5.1.1 Fugitive Dust

Fugitive dust is generally defined as natural and/or man-associated dusts that become airborne due to the forces of wind or human activity. Construction-phase fugitive dust emissions may be generated during site grading, excavation, vehicular activity, and production activities at an on-site concrete batch plant.

The quantities of fugitive dust emitted by the site construction vehicular traffic will be dependent on a number of factors, including the frequency of operations, specific operations being conducted, weather, and soil conditions. During construction, dust control measures will be used and will typically require moisture conditioning of the construction areas and along the defined roadways between these areas.

4.5.1.2 Other Air Pollutant Emissions

It is anticipated that total gaseous emissions during construction will be extremely small. Potential sources of VOC emissions include evaporative losses associated with on-site painting, refueling of construction equipment, and the application of adhesives and waterproofing chemicals. The frequency and extent of these activities are limited and they will have minimal impact on air quality.

Exhaust emissions from construction equipment will also contain small amounts of NO_x, SO_2, CO, particulate matter, and VOCs resulting from incomplete combustion of fuel. However, due to the nature of heavy-duty diesel-powered construction vehicles, which allow for more complete combustion and less volatile fuels than spark-ignited engines, these emissions are relatively low.

Open burning will emit particulate matter, CO, hydrocarbons, sulfur oxides, and NO_x. Open burning of construction debris may occur if the composition of that debris consists of wood products and other relatively clean-burning components. Pollutant emissions from debris burning will depend upon the amount and moisture content of the debris.

4.5.2 Air Quality Control Methods

The impact of heavy construction activities and site preparation on air quality will be short term and confined to the immediate vicinity of the construction activity. This is primarily because most of the fugitive dust created by construction traffic and earth-moving operations consists of relatively large particles. These large particles tend to settle quickly rather than remain suspended for transport over long distances.

Job site guidelines for minimizing emissions of fugitive dust from identifiable construction sources will include a combination of the following techniques (if applicable):

- Contractors will be instructed to comply with any applicable state and local regulations governing open-bodied trucks hauling sand, gravel, or soil between on-site and off-site areas. This could include providing covers or moistening the load with water and wheel washing to reduce dusting.
- Areas disturbed during construction will be stabilized by mulching or seeding as soon as practicable.
- When construction occurs on bare ground, water (possibly together with wetting agents) will be used as necessary to suppress dust.
- Temporary vehicular surfaces of crushed rock may be used in high traffic areas. Areas not subject to heavy traffic or continual disturbance will be wetted down using nontoxic substances to suppress dust.
- On-site concrete batch plants will be equipped with dust control systems that effectively mitigate off-site impacts.
- Sandblasting operations will be located in isolated areas to minimize effects on adjacent work areas. Protective covers will also be utilized where practicable.

Only minor short-term air quality impacts are expected to result from open burning since these operations will be conducted in compliance with Florida Division of Forestry air pollution control regulations (Chapter 62-256 F.A.C.) which are applicable in rural areas.

Because of the mitigative measures that will be employed, it is not expected that vehicular emissions, fugitive dust, or smoke from open-burning operations will present any significant air quality problems during the construction period.

4.5.3 Ambient Air Quality Monitoring Program

Air quality monitoring for construction-related fugitive dust or other air pollutants is not being proposed. Periodic visual inspections of the job site will be conducted to ensure compliance with guidelines for minimizing emissions of fugitive dust during construction of the proposed facility.

5.6 AIR QUALITY IMPACTS

5.6.1 Impact Assessment

The air quality impacts of Power Block 2 are fully discussed in Sections 6, 7, and 8 of the PSD permit application provided as Appendix 10.1.5. Therefore, the analyses that address these air quality impacts are not repeated in their entirety in this section. A summary of the results of these analyses is presented in this section.

Air quality dispersion modeling analyses of the potential impacts of air emissions from the proposed Power Block 2 were performed for those pollutants which had proposed emissions greater than the PSD significant emission rates: Particulate Matter, SO_2, NO_x, CO, and SAM. These analyses were performed to address compliance with AAQS and PSD Class I and II increments. For SAM, since there are no AAQS or PSD increments, the maximum 24-hour average SAM impact for Power Block 2 was compared to the ambient reference concentration (ARC) of 2.4 ug/m^3 that the Florida DEP formerly used to assess impacts for toxic air pollutants. The ARCs are no longer in effect for permitting purposes.

For both natural gas-firing and oil-firing conditions, the ISCST3 air dispersion model was used to determine the maximum ambient air quality impacts for nine modeling scenarios that covered the range of operating loads and air inlet temperatures that the combustion turbines for Power Block 2 would likely experience. For each fuel, the nine modeling scenarios were as follows:

- Baseload operations for air inlet temperatures of 20°F, 59°F, and 90°F (natural gas-firing)/105°F (oil firing);

- 80% load for 20°F, 59°F, 90°F (natural gas-firing)/105°F (oil firing); and
- 60% load (for natural gas-firing)/65% load (oil-firing) for 20°F, 59°F, and 90°F (natural gas-firing)/105°F (oil firing).

Pollutant concentrations were predicted in a receptor grid containing more than 700 receptors that covered an area out to 50 kilometers from the site. Concentrations were predicted using five years of surface and upper air meteorological data for the years 1987 through 1991 from the National Weather Service (NWS) stations in Tampa and Ruskin, respectively. These data have been recommended and approved for use by the DEP in previous air permit applications to address air quality impacts for proposed sources locating in Polk County and adjacent counties.

In addition, pollutant concentrations were predicted at receptor locations placed at the boundary of the Chassahowitzka National Wilderness Area (NWA), which is located 118 kilometers from the plant site and is the nearest PSD Class I area. At distances beyond 50 km from a source, the EPA and FDEP currently recommend the CALPUFF model for predicting impacts. The CALPUFF model is a long-range transport model that was specifically developed for estimating the air quality impacts in areas that are more than 50 km from a source. As a result, the CALPUFF model was used to address impacts from Power Block 2 at the Chassahowitzka NWA.

The results of the ISCST3 and CALPUFF modeling analyses are summarized in Tables 5.6-1 and 5.6-2. In Table 5.6-1, the highest concentrations predicted for Power Block 2 for each pollutant are compared to the corresponding PSD Class II significance levels, PSD Class II increments, and ambient air quality standards. In Table 5.6-2, the highest concentrations predicted for Power Block 2 at the Chassahowitzka NWA are compared to the PSD Class I significance levels. As shown in these tables, the maximum concentrations for all pollutants are predicted to be less than the EPA PSD significance levels. Therefore, Power Block 2 will not have a significant impact on the ambient air quality of central Florida. In addition, these modeling results demonstrate that the maximum impacts predicted for Power Block 2 will not cause or contribute to an exceedance of any PSD increments or ambient air quality standards. Finally, since the impact of Power Block 2 on the Chassahowitzka NWA is less than significant and based on a regional haze analysis performed, there will not be a significant impact to the visibility in the NWA.

TABLE 5.6.1-1
SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR POWER BLOCK 2 COMPARED TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Period	Maximum Concentration Predicted for Power Block 2 (a) (ug/m3)	PSD Class II Significant Impact Level (ug/m3)	PSD Class II Increment (ug/m3)	Ambient Air Quality Standard (c) (ug/m3)	Predicted Impact Greater than the PSD Significant Impact Level? (Yes/No)
Carbon Monoxide	1-Hour	34.9	2,000	N/A	40,000	No
	8-Hour	107	500	N/A	10,000	No
Nitrogen Dioxide	Annual	0.096	1	25	100	No
Sulfur Dioxide	3-Hour	17.8	25	512	1,300	No
	24-Hour	4.9	5	91	260	No
	Annual	0.038	1	20	60	No
Particulate Matter (PM_{10}) (b)	24-Hour	3.0	5	30	150	No
	Annual	0.039	1	17	50	No
Sulfuric Acid Mist	24-Hour	0.75	N/A	N/A	N/A	N/A

(a) Concentrations are the highest values for this analysis.
(b) As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.
(c) Florida AAQS, Rule 62-204.240
N/A = Not applicable
Source: Golder, 2000

TABLE 5.6.1-2

SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR POWER BLOCK 2 COMPARED TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Period	Maximum Concentration Predicted for Power Block 2 (a) (ug/m^3)	PSD Class I Significant Impact Level (ug/m3)	Predicted Impact Greater than the PSD Significant Impact Level? (Yes/No)
Sulfur Dioxide (SO_2)	3-Hour	0.46	1.0	NO
	24-Hour	0.12	0.2	NO
	Annual	0.0014	0.1	NO
Particulate Matter (PM_{10})	24-Hour	0.033	0.3	NO
	Annual	0.0010	0.2	NO
Nitrogen Dioxide (NO_2)	Annual	0.0013	0.1	NO

(a) Concentrations are the highest values for this analysis.

Source: Golder, 2000

10.1.5 Prevention of Significant Deterioration Permit Application

Following is a copy of the Prevention of Significant Deterioration (PSD) permit application for Power Block 2 submitted to the DEP pursuant to requirements of the Federal Clean Air Act.

PSD PERMIT APPLICATION

FOR

FLORIDA POWER CORPORATION
HINES ENERGY COMPLEX
POWER BLOCK 2

JUNE 2000

Florida Power Corporation
One Power Plaza
263 13th Ave. South
St. Petersburg, Florida 33701

APPLICATION FORMS

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Florida Power Corporation**	
2. Site Name: **Hines Energy Complex**	
3. Facility Identification Number: [X] Unknown	
4. Facility Location: Street Address or Other Locator: **County Road 555; 2.5 miles South of CR 640** City: **Bartow** County: **Polk** Zip Code: **33830**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **J. Michael Kennedy, Manager Air Programs**
2. Application Contact Mailing Address: Organization/Firm: **Florida Power Corporation** Street Address: **One Power Plaza, 263-13th Ave S** City: **St. Petersburg** State: **FL** Zip Code: **33701-5511**
3. Application Contact Telephone Numbers: Telephone: **(727) 826 - 4334** Fax: **(727) 826 - 4216**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	7-24-00
2. Permit Number:	1050234-004-AC
3. PSD Number (if applicable):	PSD-FL-296
4. Siting Number (if applicable):	PA 92-33

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ______________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: ______________________

Operation permit number to be revised: ______________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: ______________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised: ______________________

Reason for revision: ______________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[X] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
   W. Jeffrey Pardue, Director Environmental Services Department
2. Owner/Authorized Representative or Responsible Official Mailing Address:
   Organization/Firm: **Florida Power Corporation**
   Street Address: **One Power Plaza, 263-13th Ave S**
   City: **St. Petersburg** State: **FL** Zip Code: **33701-5511**
3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
   Telephone: (**727**) **826 - 4301** Fax: (**727**) **826 - 4216**
4. Owner/Authorized Representative or Responsible Official Statement:

   I, the undersigned, am the owner or authorized representative(check here [ ], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.*

   WJPardue 7/19/00

   Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: **Kennard F. Kosky**
   Registration Number: **14996**
2. Professional Engineer Mailing Address:
   Organization/Firm: **Golder Associates Inc.**
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3. Professional Engineer Telephone Numbers:
   Telephone: (**352**) **336 - 5600** Fax: (**352**) **336 - 6603**

4. Professional Engineer Statement:

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

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

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

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

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

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

Kennard F. Kosky — Signature

May 26, 2000 — Date

(seal) /s/

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
—	CT-1; Power Block 2	AC1A	
—	CT-2; Power Block 2	AC1A	

Application Processing Fee

Check one: [ ] Attached - Amount: $: ____________ [X] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations:

   Power Block 2 consists of two nominal 170 MW Siemens Westinghouse 501FD combustion turbines (CTs), two unfired heat recovery steam generators (HRSGs), and one 190 MW steam turbine; nominal rating of 530 MW combined cycle unit. See PSD Application. Fee included with Site Certification Application.

2. Projected or Actual Date of Commencement of Construction: **01 Nov 2001**

3. Projected Date of Completion of Construction: **01 Jul 2003**

Application Comment

This application has been submitted and will be reviewed within the Florida Power Plant Siting Act (PPSA). See PSD Application. Power Block 1 has permit PA-92-33; PSD-FL-195A.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **414.4**	North (km): **3073.9**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **27 / 47 / 19**		Longitude (DD/MM/SS): **81 / 52 / 10**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **Operation of Power Block 1 began in 1999. Power Block 1 is a nominal 470 MW combined cycle unit consisting of 2 CTs, 2 HRSG's and 1 steam turbine. The CTs fire natural gas with distillate oil as backup. The HRSGs are unfired. This application is for the addition of Power Block 2, a nominal 530 MW combined cycle application. See PSD Application.**			

Facility Contact

1. Name and Title of Facility Contact: **Paul Crimi, Plant Manager**		
2. Facility Contact Mailing Address: Organization/Firm: **Hines Energy Complex** Street Address: **7700 County Road 555** City: **Bartow**	State: **FL**	Zip Code: **33830**
3. Facility Contact Telephone Numbers: Telephone: (**863**) **519 - 6101**	Fax: (**863**) **519 - 6110**	

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **Applicable NSPS is 40 CFR Part 60; Subpart GG.**	

List of Applicable Regulations

62-212.400, F.A.C. See PSD Application	

9. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	9. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	**A**				**Particulate Matter – Total**
SO_2	**A**				**Sulfur Dioxide**
NO_X	**A**				**Nitrogen Oxides**
CO	**A**				**Carbon Monoxide**
VOC	**A**				**Volatile Organic Compounds**
SAM	**A**				**Sulfuric Acid Mist**

9. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

9. Area Map Showing Facility Location: [X] Attached, Document ID: **Fig. 1-1; PSD** [ ] Not Applicable [ ] Waiver Requested
9. Facility Plot Plan: [X] Attached, Document ID: **Fig. 2-1; PSD** [ ] Not Applicable [ ] Waiver Requested
9. Process Flow Diagram(s): [X] Attached, Document ID: **Fig. 2-2; PSD** [ ] Not Applicable [ ] Waiver Requested
9. Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID: **PSD Appl.** [ ] Not Applicable [ ] Waiver Requested
9. Fugitive Emissions Identification: [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
9. Supplemental Information for Construction Permit Application: [X] Attached, Document ID: **PSD Appl.** [ ] Not Applicable
9. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

9. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [ ] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
9. Alternative Methods of Operation: [ ] Attached, Document ID:__________ [ ] Not Applicable
9. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable
9. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [ ] Not Applicable
9. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [ ] Not Applicable
9. Compliance Report and Plan: [ ] Attached, Document ID:________ [ ] Not Applicable
9. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [ ] Not Applicable

9. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

9. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

9. Type of Emissions Unit Addressed in This Section: (Check one)

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

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

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

9. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

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

9. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

CT-1; Power Block 2

4. Emissions Unit Identification Number:
ID:

[ ] No ID
[X] ID Unknown

9. Emissions Unit Status Code: **C**	9. Initial Startup Date:	9. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [X]

9. Emissions Unit Comment: (Limit to 500 Characters)

Siemens Westinghouse 501 FD combustion turbine firing natural gas with distillate oil back-up.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_X combustion-natural gas firing** **Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.** **Water Injection – distillate oil firing**	
2. Control Device or Method Code(s): **25, 65, 28**	

Emissions Unit Details

1. Package Unit: Manufacturer: **Siemens Westinghouse**	Model Number: **501 FD**	
2. Generator Nameplate Rating:	**170** MW	
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,830	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			

Heat input is HHV with natural gas; heat input at 59°F turbine inlet temperature; MW nominal rating.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment HEC-EU1-C	
See PSD Application	

ATTACHMENT HEC-EU1-C

Applicable Requirements Listing

EMISSION UNIT ID: EU1

FDEP Rules:

Air Pollution Control-General Provisions:
62-204.800(7)(b)37. (State Only) - NSPS Subpart GG
62-204.800(7)(c) (State Only) - NSPS authority
62-204.800(7)(d)(State Only) - NSPS General Provisions
62-204.800(12) (State Only) - Acid Rain Program
62-204.800(13) (State Only) - Allowances
62-204.800(14) (State Only) - Acid Rain Program Monitoring
62-204.800(16) (State Only) - Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:
62-210.650 - Circumvention; EUs with control device
62-210.700(1) - Excess Emissions;
62-210.700(4) - Excess Emissions; poor maintenance
62-210.700(6) - Excess Emissions; notification

Acid Rain:
62-214.300 - All Acid Rain Units (Applicability)
62-214.320(1)(a),(2) - All Acid Rain Units (Application Shield)
62-214.330(1)(a)1. - Compliance Options (if 214.430)
62-214.340 - Exemptions (new units, retired units)
62-214.350(2);(3);(6) - All Acid Rain Units (Certification)
62-214.370 - All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)

62-214.430 - All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:
62-296.320(4)(b)(State Only) - CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):
62-297.310(1) - All Units (Test Runs-Mass Emission)
62-297.310(2)(b) - All Units (Operating Rate; other than CTs;no CT)
62-297.310(3) - All Units (Calculation of Emission)
62-297.310(4)(a) - All Units (Applicable Test Procedures;Sampling time)
62-297.310(4)(b) - All Units (Sample Volume)

62-297.310(4)(c)	- All Units (Required Flow Rate Range-
PM/H2SO4/F)	
62-297.310(4)(d)	- All Units (Calibration)
62-297.310(4)(e)	- All Units (EPA Method 5-only)
62-297.310(5)	- All Units (Determination of Process Variables)
62-297.310(6)(a)	- All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	- All Units (Sampling Ports)
62-297.310(6)(d)	- All Units (Work Platforms)
62-297.310(6)(e)	- All Units (Access)
62-297.310(6)(f)	- All Units (Electrical Power)
62-297.310(6)(g)	- All Units (Equipment Support)
62-297.310(7)(a)1.	- Applies mainly to CTs/Diesels
62-297.310(7)(a)2.	- FFSG excess emissions
62-297.310(7)(a)3.	- Permit Renewal Test Required
62-297.310(7)(a)4.a	- Annual Test
62-297.310(7)(a)5.	- PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	- PM FFSG semi annual test required if >200 hrs/yr
62-297.310(7)(a)7.	- PM quarterly monitoring if >100 hrs/yr
62-297.310(7)(a)9.	- FDEP Notification - 15 days
62-297.310(7)(c)	- Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	- Test Reports

Federal Rules:

NSPS Subpart GG:

40 CFR 60.332(a)(1)	- NOx for Electric Utility CTs
40 CFR 60.332(a)(3)	- NOx for Electric Utility CTs
40 CFR 60.333	- SO2 limits
40 CFR 60.334	- Monitoring of Operations (Custom Monitoring for
Gas)	
40 CFR 60.335	- Test Methods

NSPS General Requirements:

40 CFR 60.7(a)(1)	- Notification of Construction
40 CFR 60.7(a)(2)	- Notification of Initial Start-Up
40 CFR 60.7(a)(3)	- Notification of Actual Start-Up
40 CFR 60.7(a)(4)	- Notification and Recordkeeping
(Physical/Operational Cycle)	
40 CFR 60.7(a)(5)	- Notification of CEM Demonstration
40 CFR 60.7(b)	- Notification and Recordkeeping
(startup/shutdown/malfunction)	
40 CFR 60.7(c)	- Notification and Recordkeeping
(startup/shutdown/malfunction)	
40 CFR 60.7(d)	- Notification and Recordkeeping
(startup/shutdown/malfunction)	
40 CFR 60.7(f)	- Notification and Recordkeeping (maintain records-
2 yrs)	

40 CFR 60.8(a) - Performance Test Requirements
40 CFR 60.8(b) - Performance Test Notification
40 CFR 60.8(c) - Performance Tests (representative conditions)
40 CFR 60.8(e) - Provide Stack Sampling Facilities

40 CFR 60.8(f) - Test Runs
40 CFR 60.11(a) - Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b) - Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c) - Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d) - Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2) - Compliance (opacity; ref. S. 60.8)
40 CFR 60.12 - Circumvention
40 CFR 60.13(a) - Monitoring (Appendix B; Appendix F)
40 CFR 60.13(c) - Monitoring (Opacity COMS)
40 CFR 60.13(d)(1) - Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(d)(2) - Monitoring (COMS; span, system check)
40 CFR 60.13(e) - Monitoring (frequency of operation)
40 CFR 60.13(f) - Monitoring (frequency of operation)
40 CFR 60.13(h) - Monitoring (COMS; data requirements)

Acid Rain-Permits:
40 CFR 72.9(a) - Permit Requirements
40 CFR 72.9(b) - Monitoring Requirements
40 CFR 72.9(c)(1) - SO2 Allowances-hold allowances
40 CFR 72.9(c)(2) - SO2 Allowances-violation
40 CFR 72.9(c)(3)(iii) - SO2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4) - SO2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5) - SO2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d) - NOx Requirements
40 CFR 72.9(e) - Excess Emission Requirements
40 CFR 72.9(f) - Recordkeeping and Reporting
40 CFR 72.9(g) - Liability
40 CFR 72.20(a) - Designated Representative; required
40 CFR 72.20(b) - Designated Representative; legally binding
40 CFR 72.20(c) - Designated Representative; certification requirements
40 CFR 72.21 - Submissions
40 CFR 72.22 - Alternate Designated Representative
40 CFR 72.23 - Changing representatives; owners
40 CFR 72.24 - Certificate of representation
40 CFR 72.30(a) - Requirements to Apply (operate)
40 CFR 72.30(b)(2) - Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c) - Requirements to Apply (reapply before expiration)
40 CFR 72.30(d) - Requirements to Apply (submittal requirements)
40 CFR 72.31 - Information Requirements; Acid Rain Applications

40 CFR 72.32	- Permit Application Shield
40 CFR 72.33(b)	- Dispatch System ID;unit/system ID
40 CFR 72.33(c)	- Dispatch System ID;ID requirements
40 CFR 72.33(d)	- Dispatch System ID;ID change
40 CFR 72.40(a)	- General; compliance plan
40 CFR 72.40(b)	- General; multi-unit compliance options
40 CFR 72.40(c)	- General; conditional approval
40 CFR 72.40(d)	- General; termination of compliance options
40 CFR 72.51	- Permit Shield
40 CFR 72.90	- Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	- Authorized account representative
40 CFR 73.35(c)(1)	- Compliance: ID of allowances by serial number
Monitoring Part 75:	
40 CFR 75.4	- Compliance Dates;
40 CFR 75.5	- Prohibitions
40 CFR 75.10(a)(1)	- Primary Measurement; SO2;
40 CFR 75.10(a)(2)	- Primary Measurement; NOx;
40 CFR 75.10(a)(3)(iii)	- Primary Measurement; CO2; O2 monitor
40 CFR 75.10(b)	- Primary Measurement; Performance Requirements
40 CFR 75.10(c)	- Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	- Primary Measurement; Optional Backup Monitor
40 CFR 75.10(f)	- Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	- Primary Measurement; Minimum Recording
40 CFR 75.11(d)	- SO2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	- SO2 Monitoring; Gaseous firing
40 CFR 75.12(a)	- NOx Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	- NOx Monitoring; Determination of NOx emission rate; Appendix F
40 CFR 75.13(b)	- CO2 Monitoring; Appendix G
40 CFR 75.13(c)	- CO2 Monitoring; Appendix F
40 CFR 75.14(c)	- Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	- Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	- Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	- Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	- Recertification Backup/portable monitor
40 CFR 75.20(f)	- Alternate Monitoring system
40 CFR 75.21(a)	- QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	- QA/QC; Calibration Gases

40 CFR 75.21(d) - QA/QC; Notification of RATA
40 CFR 75.21(e) - QA/QC; Audits
40 CFR 75.21(f) - QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22 - Reference Methods
40 CFR 75.24 - Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3) - General Missing Data Procedures; NOx
40 CFR 75.30(a)(4) - General Missing Data Procedures; SO2
40 CFR 75.30(b) - General Missing Data Procedures; certified backup monitor
40 CFR 75.30(c) - General Missing Data Procedures; certified backup monitor
40 CFR 75.30(d) - General Missing Data Procedures; SO2 (optional before 1/1/97)
40 CFR 75.30(e) - General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31 - Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32 - Monitoring Data Availability for Missing Data
40 CFR 75.33 - Standard Missing Data Procedures
40 CFR 75.36 - Missing Data for Heat Input
40 CFR 75.40 - Alternate Monitoring Systems-General
40 CFR 75.41 - Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42 - Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43 - Alternate Monitoring Systems-Accessability Criteria
40 CFR 75.44 - Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45 - Alternate Monitoring Systems-Daily QA
40 CFR 75.46 - Alternate Monitoring Systems-Missing data
40 CFR 75.47 - Alternate Monitoring Systems-Criteria for Class
40 CFR 75.48 - Alternate Monitoring Systems-Petition
40 CFR 75.53 - Monitoring Plan ; revisions
40 CFR 75.54(a) - Recordkeeping-general
40 CFR 75.54(b) - Recordkeeping-operating parameter
40 CFR 75.54(c) - Recordkeeping-SO2
40 CFR 75.54(d) - Recordkeeping-NOx
40 CFR 75.54(e) - Recordkeeping-CO2
40 CFR 75.54(f) - Recordkeeping-Opacity
40 CFR 75.55(c) - General Recordkeeping (Specific Situations)
40 CFR 75.55(e) - General Recordkeeping (Specific Situations)
40 CFR 75.56 - Certification; QA/QC Provisions
40 CFR 75.60 - Reporting Requirements-General
40 CFR 75.61 - Reporting Requirements-Notification cert/recertification
40 CFR 75.62 - Reporting Requirements-Monitoring Plan
40 CFR 75.63 - Reporting Requirements-Certification/Recertification
40 CFR 75.64(a) - Reporting Requirements-Quarterly reports; submission

40 CFR 75.64(b) statement	- Reporting Requirements-Quarterly reports; DR
40 CFR 75.64(c) Certification	- Rep. Req.; Quarterly reports; Compliance
40 CFR 75.64(d)	- Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	- Petitions to the Administrator (if required)
Appendix A-1	- Installation and Measurement Locations
Appendix A-2.	- Equipment Specifications
Appendix A-3.	- Performance Specifications
Appendix A-4.	- Data Handling and Acquisition Systems
Appendix A-5.	- Calibration Gases
Appendix A-6.	- Certification Tests and Procedures
Appendix A-7.	- Calculations
Appendix B	- QA/QC Procedures
Appendix C-1.	- Missing Data; SO2/NOx for controlled sources
Appendix C-2.	- Missing Data; Load-Based Procedure; NOx & flow
Appendix D	- Optional SO2; Oil-/gas-fired units
Appendix F	- Conversion Procedures
Appendix H	- Traceability Protocol

Acid Rain Program-Excess Emissions (these are future requirements):

40 CFR 77.3	- Offset Plans (future)
40 CFR 77.5(b)	- Deductions of Allowances (future)
40 CFR 77.6	- Excess Emissions Penalties (SO2 and NOx;future)

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **Fig 2-1**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **125** feet	7. Exit Diameter: **19** feet
8. Exit Temperature: **190** °F	9. Actual Volumetric Flow Rate: **1,009,487** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: **17** East (km): **414.4** North (km): **3073.9**	
14. Emission Point Comment (limit to 200 characters): **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 2-1 and 2-2 in PSD application.**	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.92**	5. Maximum Annual Rate: **15,564**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,030**
10. Segment Comment (limit to 200 characters): **Based on 1,030 BTU/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 Gallons Used**	
4. Maximum Hourly Rate: **14.9**	5. Maximum Annual Rate: **13,683**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **141.2**
10. Segment Comment (limit to 200 characters): **BTU based on HHV of 141.2 MMBtu/1,000 gallons. Aggregate fuel usage of 27,365,000 gallons per year requested for Power Block 2.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_X	026	065	EL
CO			EL
VOC			EL
SAM			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION (Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 64.8 lb/hour 60.3 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Siemens Westinghouse, 2000	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See Section 2.0 and Appendix A in PSD Application	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 % Opacity	4. Equivalent Allowable Emissions: 7.3 lb/hour 34.4 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 9	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20% Opacity**	4. Equivalent Allowable Emissions: **64.8** lb/hour **29.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **105.6** lb/hour **68.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Section 2.0 and Appendix A in PSD Application**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Pipeline Gas**	4. Equivalent Allowable Emissions: **6** lb/hour **22.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:	
3. Potential Emissions: lb/hour tons/year		4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/year		
6. Emission Factor: Reference:		7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 % Sulfur Oil**	4. Equivalent Allowable Emissions: **105.6** lb/hour **48.6** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_X

2. Total Percent Efficiency of Control:

3. Potential Emissions: 116.9 lb/hour 144.3 tons/year

4. Synthetically Limited? [X]

5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor:
   Reference: Siemens Westinghouse, 1998

7. Emissions Method Code: 2

8. Calculation of Emissions (limit to 600 characters):

   Maximum lb/hour based on oil-firing. See Section 2.0 and Appendix A in PSD Application.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: 3.5 ppmvd at 15% O_2

4. Equivalent Allowable Emissions: 25.0 lb/hour 101.2 tons/year

5. Method of Compliance (limit to 60 characters):

   CEM; part 75; 24-hour block load-weighted average; 7 a.m. to 7 a.m.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_X	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **116.9** lb/hour **54.7** tons/year
5. Method of Compliance (limit to 60 characters): **CEM; Part 75; 24-hour block load-weighted average; 7 a.m. to 7 a.m.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 154 lb/hour 372 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Siemens Westinghouse, 2000	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): See Section 2.0 and Appendix A in PSD Application	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Max lb/hr for gas firing at 60% load and 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas includes 3,000 hrs at 60% load; equivalent of 1,000 hrs/yr/CT-oil.	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 ppmvd – Base Load/50 ppmvd at 60% load	4. Equivalent Allowable Emissions: 154 lb/hour 340 tons/year
5. Method of Compliance (limit to 60 characters): EPA Method 10 @ 15% O_2	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Gas Firing: lb/hr at 20°F turbine inlet 60% load; TPY for 5,760 hrs/yr (100% load) and 3,000 hours (60% load) at 59°F turbine inlet.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **30 ppmvd**	4. Equivalent Allowable Emissions: **112** lb/hour **53** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22** lb/hour **28.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Section 2.0 and Appendix A in PSD Application**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas (100% and 60% loads); equivalent of 1,000 hrs/yr/CT-oil.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.8 ppmvd – Baseload/ 3 ppmvd – 60% load**	4. Equivalent Allowable Emissions: **5.3** lb/hour **20** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; at 15% O_2**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 60% load 20°F turbine inlet; TPY for 5,760 hrs/yr (100% load) and 3,000 hrs (60% load) at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 ppmvw**	4. Equivalent Allowable Emissions: **22** lb/hour **10.5** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.2** lb/hour **10.5** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **10 % SO_2** Reference: **Golder, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Emission Factor is converted to SAM. See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Pipeline Gas**	4. Equivalent Allowable Emissions: **0.9** lb/hour **3.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 % Sulfur oil**	4. Equivalent Allowable Emissions: **16.2** lb/hour **7.44** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment (limit to 200 characters): **Gas Firing**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Not Yet Determined** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_X CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: VE20	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Method 9.	
5. Visible Emissions Comment (limit to 200 characters): Oil Firing	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: EM	2. Pollutant(s): NO_X
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Siemens Westinghouse Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request NO_X CEM in lieu of WTF monitoring	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: VE99	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 60 min/hour	
4. Method of Compliance: None	
5. Visible Emissions Comment (limit to 200 characters): FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunction.	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ______ of ______

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: Fig 2-2 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Tab 2-4/2-5 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: Sec 4.0 [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD Appl. [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD Appl. [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD Appl. [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [ ] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [ ] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [ ] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID:________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

2. Regulated or Unregulated Emissions Unit? (Check one)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

CT-2; Power Block 2

4. Emissions Unit Identification Number: [ ] No ID
ID: [X] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)

Siemens Westinghouse 501 FD combustion turbine firing natural gas with distillate oil back-up.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

   Dry Low NO_X combustion-natural gas firing

   Selective Catalytic Reduction (SCR) – natural gas firing/ distillate oil firing.

   Water Injection – distillate oil firing

2. Control Device or Method Code(s): **25, 65, 28**

Emissions Unit Details

1. Package Unit:
   Manufacturer: **Siemens Westinghouse** Model Number: **501 FD**
2. Generator Nameplate Rating: **170** MW
3. Incinerator Information:
   Dwell Temperature: °F
   Dwell Time: seconds
   Incinerator Afterburner Temperature: °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,830	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): Heat input is HHV with natural gas; heat input at 59°F turbine inlet temperature; MW nominal rating.			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment HEC-EU1-C	
See PSD Application	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **Fig 2-1**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **125** feet	7. Exit Diameter: **19** feet
8. Exit Temperature: **190** °F	9. Actual Volumetric Flow Rate: **1,009,487** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: **17** East (km): **414.4** North (km): **3073.9**	
14. Emission Point Comment (limit to 200 characters): **Temperature and flow for natural gas at 59°F turbine inlet; See Tables 2-1 and 2-2 in PSD application.**	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

   Natural Gas

2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.92**	5. Maximum Annual Rate: **15,564**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,030**

10. Segment Comment (limit to 200 characters):

    Based on 1,030 BTU/CF (HHV); maximum hourly at 20°F; annual at 59°F; turbine inlet temperatures.

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

   Distillate Fuel Oil

2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 Gallons Used**	
4. Maximum Hourly Rate: **14.9**	5. Maximum Annual Rate: **13,683**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **141.2**

10. Segment Comment (limit to 200 characters):

    BTU based on HHV of 141.2 MMBtu/1,000 gallons. Aggregate fuel usage of 27,365,000 gallons per year requested for Power Block 2.

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_X	026	065	EL
CO			EL
VOC			EL
SAM			EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **64.8** lb/hour **60.3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Section 2.0 and Appendix A in PSD Application**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 % Opacity**	4. Equivalent Allowable Emissions: **7.3** lb/hour **34.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **20% Opacity**	4. Equivalent Allowable Emissions: **64.8** lb/hour **29.8** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: **105.6** lb/hour **68.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Section 2.0 and Appendix A in PSD Application**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Pipeline Gas**	4. Equivalent Allowable Emissions: **6** lb/hour **22.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 % Sulfur Oil**	4. Equivalent Allowable Emissions: **105.6** lb/hour **48.6** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: NO_X	2. Total Percent Efficiency of Control:
3. Potential Emissions: 116.9 lb/hour 144.3 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Siemens Westinghouse, 1998	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Maximum lb/hour based on oil-firing. See Section 2.0 and Appendix A in PSD Application.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 3.5 ppmvd at 15% O_2	4. Equivalent Allowable Emissions: 25.0 lb/hour 101.2 tons/year
5. Method of Compliance (limit to 60 characters): CEM; part 75; 24-hour block load-weighted average; 7 a.m. to 7 a.m.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **15 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **116.9** lb/hour **54.7** tons/year
5. Method of Compliance (limit to 60 characters): **CEM; Part 75; 24-hour block load-weighted average; 7 a.m. to 7 a.m.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: CO
2. Total Percent Efficiency of Control:
3. Potential Emissions: 154 lb/hour 372 tons/year
4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor:

   Reference: Siemens Westinghouse, 2000
7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters):

   See Section 2.0 and Appendix A in PSD Application
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

   Max lb/hr for gas firing at 60% load and 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas includes 3,000 hrs at 60% load; equivalent of 1,000 hrs/yr/CT-oil.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:

   10 ppmvd – Base Load/50 ppmvd at 60% load
4. Equivalent Allowable Emissions:

   154 lb/hour 340 tons/year
5. Method of Compliance (limit to 60 characters):

   EPA Method 10 @ 15% O_2
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

   Gas Firing: lb/hr at 20°F turbine inlet 60% load; TPY for 5,760 hrs/yr (100% load) and 3,000 hours (60% load) at 59°F turbine inlet.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **30 ppmvd**	4. Equivalent Allowable Emissions: **112** lb/hour **53** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; Initial and Annual at Base Load**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22** lb/hour **28.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **Siemens Westinghouse, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Section 2.0 and Appendix A in PSD Application**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas (100% and 60% loads); equivalent of 1,000 hrs/yr/CT-oil.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.8 ppmvd – Baseload/ 3 ppmvd – 60% load**	4. Equivalent Allowable Emissions: **5.3** lb/hour **20** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; at 15% O_2**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 60% load 20°F turbine inlet; TPY for 5,760 hrs/yr (100% load) and 3,000 hrs (60% load) at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10 ppmvw**	4. Equivalent Allowable Emissions: **22** lb/hour **10.5** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.2** lb/hour **10.5** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **10 % SO_2** Reference: **Golder, 2000**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Emission Factor is converted to SAM. See Section 2.0 and Appendix A in PSD Application.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Max lb/hr for oil firing at 20°F turbine inlet; TPY at 59°F turbine inlet with 7,760 hrs/yr-gas; equivalent of 1,000 hrs/yr/CT-oil.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Pipeline Gas**	4. Equivalent Allowable Emissions: **0.9** lb/hour **3.4** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas Firing: lb/hr at 20°F turbine inlet; TPY for 8,760 hrs/yr at 59°F turbine inlet.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 % Sulfur oil**	4. Equivalent Allowable Emissions: **16.2** lb/hour **7.44** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling - Vendor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil Firing: lb/hr at 20°F turbine inlet; TPY equivalent of 1,000 hrs/yr/CT-oil at 59°F turbine inlet.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment (limit to 200 characters): **Gas Firing**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Not Yet Determined** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_X CEM required by 40 CFR Part 75. A carbon dioxide or oxygen monitor will be included.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9.**	
5. Visible Emissions Comment (limit to 200 characters): **Oil Firing**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Manufacturer: **Siemens Westinghouse** Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request NO_X CEM in lieu of WTF monitoring**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunction.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor ______ of ______

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: Fig 2-2 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Tab 2-4/2-5 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: Sec 4.0 [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: PSD Appl. [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: PSD Appl. [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: PSD Appl. [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:_______ [ ] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:_______ [ ] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:_______ [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:_______ [ ] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID:_______

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:_______

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:_______

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:_______

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:_______

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:_______

    [ ] Not Applicable

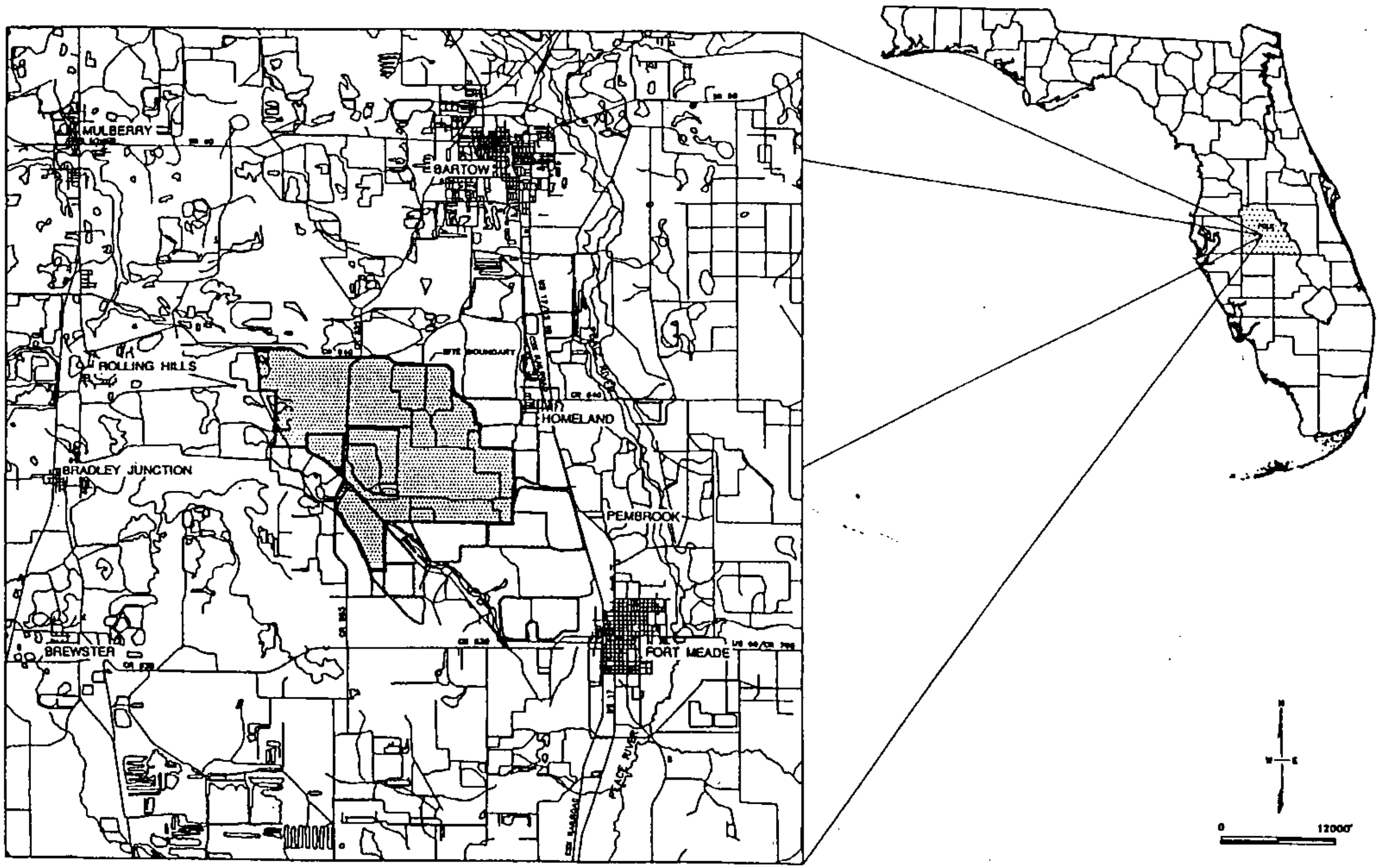
1.0 INTRODUCTION

Florida Power Corporation (FPC) has recently begun operation of Power Block 1, 470 megawatts (MW-nominal 500 MW) of combined cycle power generation at FPC's Hines Energy Complex. The generating units are located in the southwest portion of Polk County, about seven miles south-southwest of Bartow and five miles west-northwest of Fort Meade (see Figure 1-1). Future generating units are to be brought on-line sequentially, with the scheduling of units to match the estimated growth of demand through the ultimate site capacity of up to 3,000 MW. The expansion of generating capacity at the Hines Energy Complex will be accomplished using the most efficient generating technology throughout the life of the project. This approach offers FPC maximum flexibility and cost control as both technology advances and electrical demand increases.

Power Block 2 consists of two nominal 170 MW Siemens Westinghouse 501 FD combustion turbines (CTs), two unfired heat recovery steam generators (HRSGs), and one nominal 190 MW steam turbine generator (STG); i.e., a two-on-one configuration. The total nominal rating for Power Block 2 is approximately 530 MW. Pipeline quality natural gas will be utilized as the primary fuel with limited use of low sulfur fuel oil as the back-up fuel. Among the advantages of this combined cycle (CC) technology are its fuel flexibility, modularity, and efficiency. Because of the modularity of CC units, they can be sized and built incrementally to match demand without losing the economy of scale. Applications for the remaining site capacity will be submitted in the future, as appropriate.

The U.S. Environmental Protection Agency (EPA) has promulgated Prevention of Significant Deterioration (PSD) regulations (40 CFR 51.166), which require a permit review and approval for new or modified sources that increase air pollutant emissions above specified threshold levels. These emission threshold levels will be exceeded for several criteria pollutants during operation of Power Block 2. As a result, Power Block 2 is subject to PSD review for these pollutants. The Federal PSD regulations are implemented in Florida by the Florida Department of Environmental Protection (FDEP). FDEP's PSD regulations are codified in Rule 62-212.400 F.A.C. The technical information and analysis required by the federal and state PSD regulations are contained in this PSD permit application. Although this document will be an appendix to the Site Certification Application (SCA) and only addresses Power Block 2, it has been prepared as a stand-alone PSD permit application. The permit application is divided into eight major sections.

Presented in Section 2.0 is a description of the facility, including air pollutant emissions and stack parameters. Air quality review requirements and applicability are presented in Section 3.0. The best available control technology (BACT) evaluation is presented in Section 4.0. An ambient air quality monitoring data analysis is presented in Section 5.0, and the air quality modeling methodology, the results of the air quality impact assessment, and additional impacts analysis performed for the proposed project are presented in Sections 6.0, 7.0, and 8.0, respectively. Section 9.0 contains a list of references and materials cited.



SOURCE: 1992 SCA

Florida Power CORPORATION

Hines Energy Complex

FIGURE 1-1
SITE LOCATION MAP

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2.1 GENERAL DESCRIPTION

The proposed Power Block 2 project will consist of the construction of approximately 530 MW of generation. The CC configuration consists of two CTs, two HRSGs, and one steam turbine. In this "two-on-one" configuration, each of the two CTs are nominally rated at 170 MW, and the steam turbine has a nominal rating of 190 MW. Each CT will be served by a single HRSG, exhausting to an individual stack. There will be no HRSG bypass stacks for simple cycle operation. Also, there will be no supplemental firing of the HRSGs. The expected primary fuel is natural gas, with low sulfur fuel oil as a backup.

The CC units will utilize low sulfur fuel to limit sulfur dioxide (SO_2) emissions and sulfuric acid mist, selective catalytic reduction (SCR) to limit emissions of oxides of nitrogen (NO_X), and good combustion practices and clean fuels for the minimization of particulate matter (PM/PM_{10}), carbon monoxide (CO), volatile organic compounds (VOCs), and other (trace metals) emissions. The proposed emission control techniques are described in detail in Section 4.0 of this application.

2.2 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

As the steam turbine is not a combustion source, estimated mass emissions are based on operation of only the CTs. However, the exhaust gas characteristics reflect flow through the HRSG (i.e., the characteristics reflect the impact of the steam turbine). Therefore, the estimated stack emissions that are representative of the advanced CT designs proposed for Power Block 2 are presented in Tables 2-1 and 2-2 for a 170 MW CT unit (refer to Appendix A for detailed turbine performance and emissions data). The exhaust parameters presented in these tables are reflective of the combined cycle configuration. These tables cover the natural gas and fuel oil cases for three compressor inlet temperatures: 1) the high temperature case of 105°F for oil and 90°F for gas, 2) the ISO reference temperature case of 59°F and 3) the low temperature case that represents the shaft limit or the maximum physical output of the equipment, i.e., 20°F for oil/natural gas. Maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr) are projected to occur for operations at low compressor inlet temperature and base (100 percent) load operation. Maximum annual potential emission rates (after the application of BACT) for the proposed sources with respect to regulated criteria air pollutants and regulated non-criteria air pollutants are presented in Table 2-3.

Worst-case air quality impacts due to the proposed facility are a function of emission rate and plume rise. Although it is not practical to model all possible operating scenarios for the facility, a number of cases (combinations of operating conditions and fuel types) were examined to represent the range that will occur during actual operations. The low (20°F) and high (105°F oil/90°F gas) compressor inlet temperatures and a range of loads (100 to 60 percent for natural gas and 100 to 65 percent for oil) represent the range of combustion turbine performance and emissions/exhaust characteristics that will occur during normal operation. At high compressor inlet temperatures, the units cannot generate as much power because of lower inlet air density. To compensate for a portion of the loss of output (which can be on the order of 20 MW compared to referenced temperatures), inlet cooling is proposed to be installed ahead of the combustion turbine inlet. Therefore, the 59°F temperature case represents a conservative average temperature condition for estimating annual emissions for Power Block 2, inclusive of potential inlet cooling.

A review of the CT unit design information in Tables 2-1 and 2-2 indicates that the highest criteria air pollutant emission rates (SO_2, PM/PM_{10}, NO_X, CO, and VOCs) occur when burning fuel oil. Combustion of fuel oil also results in higher exhaust gas flow rates and stack exit temperatures, which are directly related to plume rise. Although the highest emission rates occur under the low compressor inlet temperature (20°F) condition, the lowest exhaust gas volumetric flow rate for the CC units occurs under the 105°F ambient temperature condition. Detailed discussion on the determination of worst-case impacts is presented in Section 6.0 (Air Quality Modeling Methodology).

Typical fuel analyses for natural gas and fuel oil are presented in Tables 2-4 and 2-5, respectively. For oil firing, it is requested that an aggregate annual fuel usage for Power Block 2 of 27,365,000 gallons be included as a permit condition. This equates to a maximum of 1,000 hours per year per combustion turbine of generation at full load (59° F).

2.3 SITE LAYOUT AND STRUCTURES

The site arrangement for the initial nominal 1,000 MW (combined Power Blocks 1 and 2) is depicted in Figure 2-1. This configuration arrangement includes the existing 470 MW

CC unit, as well as the proposed 530 MW Power Block 2, each with two CTs, two HRSGs, and one steam turbine. The four HRSG stacks are arranged in an east-west line. The flow diagram for a single 265 MW CC unit is depicted in Figure 2-2.

Stack sampling facilities will be constructed in accordance with Rule 62-297.310(6) F.A.C.

TABLE 2-1
COMBUSTION TURBINE UNIT (170 MW)
ESTIMATED [1] PERFORMANCE ON NATURAL GAS

CONDITIONS			
Ambient Temperature (°F)	20	59	90
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Maximum Heat Input Rate (MMBtu/hr)[2]	2,012	1,830	1,705
EMISSIONS (lb/hr)			
Carbon Monoxide (10 ppm at 15% O_2)	46	42	37
Nitrogen Oxides (3.5 ppmvd at 15% O_2)[3]	25.0	23.1	21.2
Sulfur Dioxide	5.6	5.1	4.8
Particulate Matter (PM_{10})	8.5	7.9	7.2
Opacity (%)	10	10	10
VOCs (1.8 ppmvd at 15% O_2)	4.7	4.4	3.8
Lead	Neg.	Neg.	Neg.
Sulfuric Acid Mist	0.9	0.8	0.7
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	190	190	190
Stack Gas Exit Velocity (ft/sec)	63.3	59.2	55.4

Notes: (1) Emission estimates based on manufacturer's data; see Appendix A

(2) For CTs the heat-input rate is based on the higher heating value (HHV) of the fuel (1,030 Btu/SCF, 23,345 Btu/lb).

(3) Not corrected to ISO conditions.

VOCs = Volatile Organic Compounds   Neg. = Negligible

Source: Seimens-Westinghouse, 2000

TABLE 2-2 COMBUSTION TURBINE UNIT (170 MW) ESTIMATED [1] PERFORMANCE ON FUEL OIL			
CONDITIONS			
Ambient Temperature (°F)	20	59	105
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Maximum Heat Input Rate (MMBtu/hr)[2]	2,100	1,932	1,707
EMISSIONS (lb/hr)			
Carbon Monoxide (30 ppmvd)	112	106	91
Nitrogen Oxides (15 ppmvd at 15% O_2)	116.9	109.4	96.7
Sulfur Dioxide	105.6	97.1	85.8
Particulate Matter (PM_{10})	64.8	59.6	52.5
Opacity (%)	20	20	20
Volatile Organic Compounds (10 ppmvw)	22	21	19
Lead [4]	0.022	0.021	0.018
Sulfuric Acid Mist	16	15	13
STACK PARAMETERS			
Stack Height (ft)	125	125	125
Stack Diameter (ft)	19.0	19.0	19.0
Stack Gas Temperature (°F)	270	270	270
Stack Gas Exit Velocity (ft/sec)	69.4	67.0	60

Notes: (1) Emission estimates based on manufacturer's data; see Appendix A.
(2) For CTs the heat input rate is based on the higher heating value (HHV) of the fuel (19,892 Btu/lb).

Source: Seimens–Westinghouse, 2000

TABLE 2-3

MAXIMUM POTENTIAL ANNUAL EMISSIONS (530 MW) AND PSD SIGNIFICANCE VALUES

Pollutant	Emissions (TPY)[a]	PSD Significant Emission Rate (TPY)	PSD Review Required (Yes/No)
Carbon Monoxide	744	100	Yes
Nitrogen Oxides	289	40	Yes
Sulfur Dioxide	137	40	Yes
Particulate Matter (PM_{10})	121	15	Yes
Total Suspended Particulates	121	25	Yes
Volatile Organic Compounds	57	40	Yes
Lead	0.02	0.6	No
Sulfuric Acid Mist	21	7	Yes
Mercury	0.001	0.1	No
MWC Organics (2, 3, 7, 8 TCDD)	7.5×10^{-7}	3.5×10^{-6}	No
MWC Metals (Be & Cd)	0.007	15	No
MWC Gases (HCl)	0.4	40	No
Total HAPs	7.3	25[b]	No

[a]TPY = Tons per year for the proposed Power Block 2 project.

Basis: Refer to Table A-25 in Appendix A.

[b]Criteria for review under 112 g regulations for determination of MACT.

MWC = municipal waste combustor.

Source: Golder, 2000

TABLE 2-4
TYPICAL NATURAL GAS ANALYSIS

ANALYSIS	MOLE (%)
Carbon Dioxide	0.576
Ethane	2.18
Hexanes Plus	0.0077
Iso-Butane	0.064
Methane	96.55
Nitrogen	0.213
Normal-Butane	0.063
Pentanes Plus	0.018
Propane	0.299
Total:	100.000
Specific Gravity (air at 1)	0.5782

Quality Information	Parameters
Heating Value (HHV)	130 Btu/cf
Total Sulfur (Maximum)	1 grain/100 SCF

Source: Florida Gas Transmission

TABLE 2-5

TYPICAL NO. 2 FUEL OIL ANALYSIS

NO. 2 DISTILLATE OIL	PERCENT (BY WEIGHT)
Carbon Residue	<0.01
Nitrogen	0.015[a]
Sulfur	0.05[b]
Ash	0.05[a]

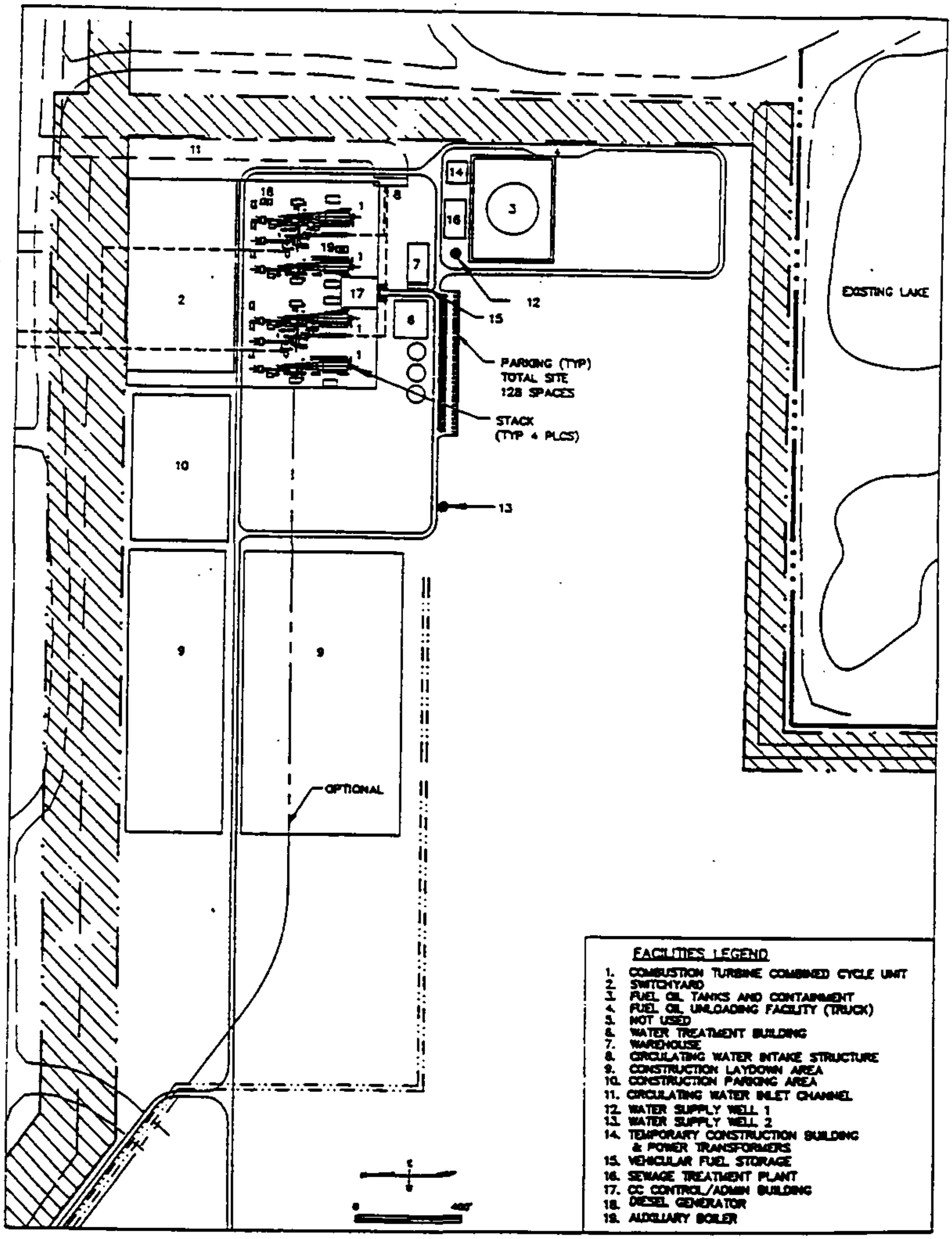
Lower Heating Value: 17,290 Btu/lb

Higher Heating Value: 19,892 Btu/lb

[a] Emission guarantees based on these values.

[b] The sulfur content is the maximum, as required by permit.

Source: FPC, 1999



Florida Power CORPORATION

HINES ENERGY COMPLEX

FIGURE 2-1
SITE ARRANGEMENT

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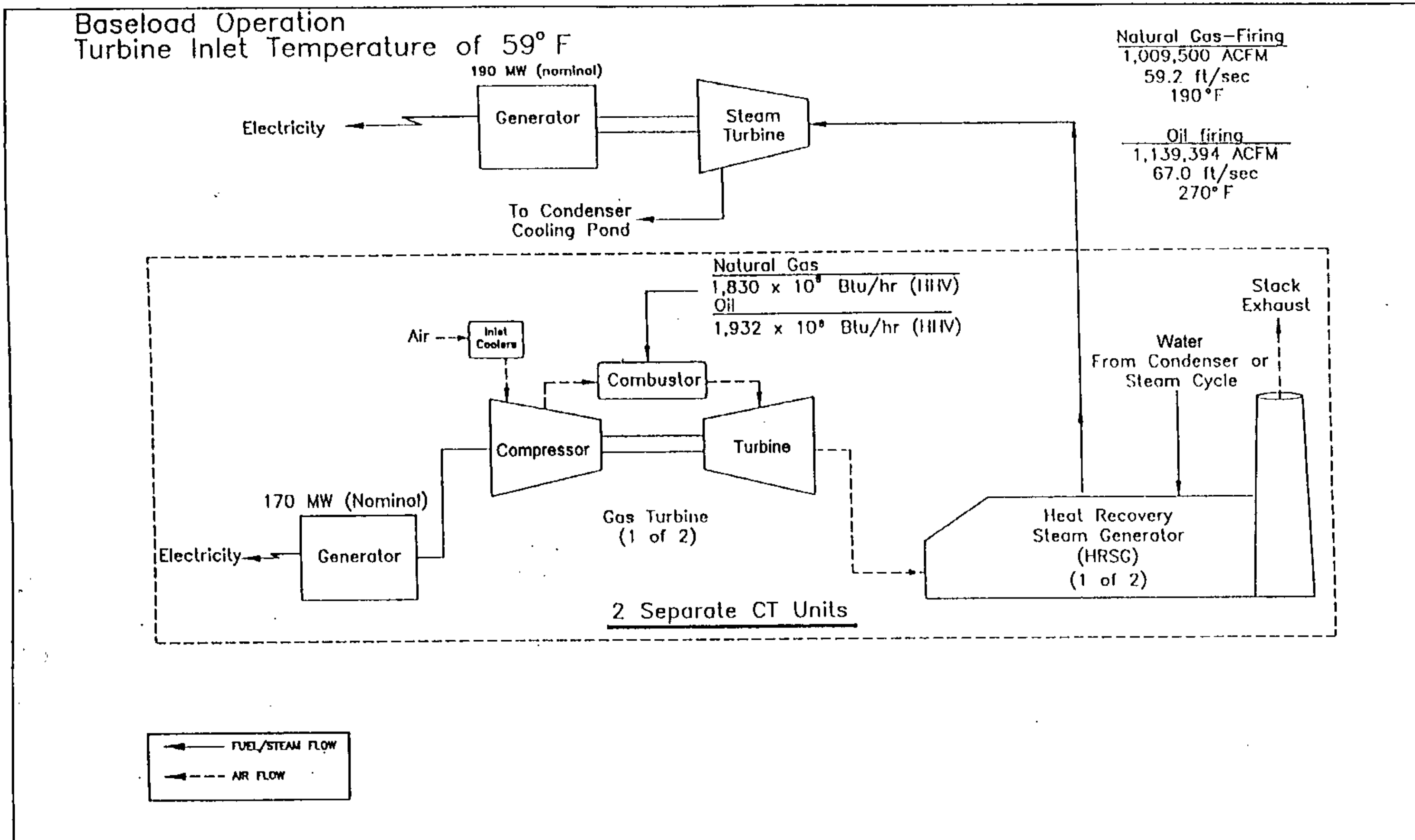


Florida Power CORPORATION

Hines Energy Complex

FIGURE 2-2
POWER BLOCK 2
PROCESS FLOW DIAGRAM
BASELOAD OPERATION, TURBINE INLET TEMPERATURE OF 59°F

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to Power Block 2. These regulations must be satisfied before the proposed facility can be constructed and begin operation.

3.1 NATIONAL AND FLORIDA AMBIENT AIR QUALITY STANDARDS (NAAQS/FAAQS)

The applicable federal and state ambient air quality standards are presented in Table 3-1 (PSD increments are also presented in Table 3-1, but discussed in Section 3.2.2). The primary National Ambient Air Quality Standards and Florida Ambient Air Quality Standards (NAAQS/FAAQS) were promulgated to protect the public health, and the secondary NAAQS/FAAQS were promulgated to protect the public health and welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Polk County is an attainment area for all criteria pollutants, meaning that existing ambient concentrations meet the allowable standards.

3.2 PSD REVIEW REQUIREMENTS

3.2.1 General Requirements

Under the federal and FDEP Prevention of Significant Deterioration (PSD) permit review requirements, all major new or modified existing sources of air pollutants located in attainment areas and regulated under the Clean Air Act (CAA) must be reviewed and approved. A "major stationary source" is defined as any one of 28 specified source categories which has the potential to emit 100 tons per year (TPY) or more, or any other stationary source which has the potential to emit 250 TPY or more of any air pollutant regulated under the CAA. Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr of heat input comprise one of the 28 specified source categories. As Power Block 2 constitutes a modification to an existing major source, the proposed project "potential to emit" is compared to the PSD significant emission rates (TPY). The term "potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. As presented earlier in Table 2-3, the potential emissions from the proposed project will exceed the significance rates for all criteria pollutants; therefore, the project is considered a modification to an existing major stationary source and is subject to PSD review.

PSD review is used to ensure that significant air quality deterioration will not result from the new or modified source located in an attainment area. The PSD regulations are contained in rule 62-212.400 F.A.C. Major sources and modifications are required to undergo the following analyses under PSD for each air pollutant emitted where potential emissions exceed the significant emission rates:

- A control technology analysis;
- An air quality impacts analysis; and
- An additional impacts analysis.

In addition to these analyses, a new source must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations (EPA, 1985a), New Source Performance Standards (NSPS), and any applicable state emission standard as discussed in Section 3.3.

3.2.2 PSD Increments/Classifications

In promulgating the 1977 Clean Air Act (CAA) Amendments, Public Law 95-95, Congress specified that certain increases above an air quality "baseline concentration" level for SO_2 and TSP concentrations would constitute "significant deterioration." The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have a significant impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress designated PSD areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would allow greater deterioration than Class II areas, were designated. EPA subsequently incorporated the requirements for classifications and area designation into the PSD regulations.

On October 17, 1988, the EPA promulgated regulations to prevent significant deterioration due to NO_X emissions and established PSD increments for NO_2 concentrations. The allowable PSD increments for SO_2, TSP, and NO_2 are presented in Table 3-1. The FDEP has adopted the EPA PSD classification scheme and the allowable PSD increments for SO_2, PM_{10}, and NO_2.

The term "baseline concentration" is derived from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and contributions from certain additional baseline sources. The PSD regulations (40 CFR 51.166) define baseline concentration as the ambient concentration level which exists in the baseline area at the time of the applicable baseline date. Emission increases after the baseline date consume PSD increments. A baseline concentration is determined for each pollutant for which PSD increments are promulgated and a baseline date is established. The baseline concentration includes:

- The actual emissions representative of sources in existence on the applicable baseline date; and

- The allowable emissions of major stationary sources which commenced construction before January 6, 1975, for SO_2 and PM_{10} concentrations, or before February 8, 1988, for NO_2 concentrations, but which were not in operation by the applicable baseline date.

The air quality analysis results which demonstrate project compliance with these requirements are presented in Section 7.0.

3.2.3 Control Technology

The control technology review requirements of the PSD regulations require that all applicable federal and state emission limiting standards be met and that Best Available Control Technology (BACT) be applied to control emissions from the source. The BACT requirements apply to all applicable regulated and unregulated air pollutants for which the increase in emissions from the source or modification exceeds significant emission rate.

BACT is defined in rule 62-210.200 F.A.C. as:

> An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.
>
> (a) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emission unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.
>
> (b) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

The requirements for BACT were incorporated within the PSD framework in the 1977 CAA Amendments. The primary purpose of BACT is to minimize consumption of PSD increments and thereby increase the potential for future economic growth without significantly degrading air quality. Guidelines for the evaluation of BACT can be found in the draft "New Source Review Workshop Manual" (EPA, 1990b) and the draft "Top-Down BACT Guidance Document" (EPA, 1990c). These guidelines were issued by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. The "top-down" approach to BACT has been followed in this application. BACT is determined on a case-by-case basis, and BACT for a source in one area may not be the same for an identical source located in another area. BACT analyses for the same types of emissions units and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, at a minimum, demonstrate compliance with NSPS for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A determination of BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts. Section 4.0 presents the BACT discussion and recommendations for this project.

3.2.4 Ambient Air Quality Monitoring Requirements

In accordance with the requirements of Rule 62-212.400(5)(f) F.A.C., any application for a PSD permit must contain an analysis of ambient air quality monitoring data in the area affected by the proposed major stationary source or major modification.

In accordance with Rule 62-212.400(5)(f)(2), ambient air monitoring for a period of up to one year may be required to satisfy the PSD monitoring requirements. A minimum of four months of data would be required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered.

However, the FDEP PSD regulations include an exemption which excludes or limits the pollutants for which an ambient air quality analysis must be conducted (Rule 62-212.400(3)(e)). This exemption states that a proposed major stationary source or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the source or modification would cause, in any area, air quality impacts less than the *de minimis* air quality impact levels presented in Table 3-2.

Ambient air quality monitoring data is discussed in Section 5.0 of this application.

3.2.5 Source Impact Analysis

A source impact analysis of air quality must be performed for a proposed major source subject to PSD for each air pollutant for which the increase in emissions exceeds the significant emission rate. The PSD regulations specifically require the use of atmospheric dispersion models in performing air quality impact analysis, estimating baseline and future air quality levels, and determining compliance with NAAQS/FAAQS and allowable PSD increments. Reference EPA models must normally be used in performing the impact analysis. Use of nonreference EPA models requires EPA's consultation and prior approval. Guidance for the regulatory application of dispersion models is presented in the U.S. EPA "Guideline on Air Quality Models (Revised)" (EPA, 1997). The modelling methodology utilized for the source impact analysis is described in detail in Section 6.0 of this application.

3.2.6 Additional Impacts Analysis

In addition to air quality impact analyses, the PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source. These analyses are to be conducted primarily for PSD Class I areas. Impacts on air quality due to general commercial, residential, industrial, and other growth related activities associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant quantities. Section 8.0 of this application contains the additional impact analyses.

3.3 OTHER REQUIREMENTS

In addition to the requirements of the PSD program, any new or modified source of air pollution must be reviewed with respect to the GEP stack height regulations (EPA, 1985a), the federal NSPS requirements, and any state-specific emission standards.

3.3.1 Good Engineering Practice (GEP) Stack Height

The 1977 CAA Amendments require under Section 123 that the degree of emission limitation required for control of any air pollutant not be affected by a stack height that exceeds GEP, or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a).

The EPA's final stack height regulations define GEP stack height in part as the greater of:

(1) 65 meters, measured from the ground-level elevation at the base of the stack; or

(2) $H_g = H + 1.5\ L$

where:

H_g = GEP stack height, measured from the ground-level elevation at the base of the stack;

H = Height of nearby structure(s) measured from the ground-level elevation at the base of the stack; and

L = Lesser dimension, height or projected width of nearby structure(s).

The term "nearby" is defined by the GEP stack height regulations as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height credit used in modelling for determining compliance with NAAQS/FAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. In this case the proposed stacks for each unit is 125.0 feet (38.1 meters) above ground level. This height does not exceed the de minimus GEP stack height of 65m. See Section 6.7 of this application for a discussion of building downwash considerations for this project.

3.3.2 New Source Performance Standards (NSPS)

The CAA required the U.S. EPA to adopt standards of performance for new or modified stationary sources of air pollution. To date, the U.S. EPA has adopted regulations for approximately 80 stationary source categories. These regulations are contained in 40 CFR Part 60. A review of the regulations reveals that the Power Block 2 CC units are subject to a specific NSPS. Any source subject to a specific NSPS is also subject to the general provisions of 40 CFR 60 Subpart A.

3.3.2.1 General Provisions

The general provisions of the NSPS regulations are found in 40 CFR 60, Subpart A. The general provisions specify the notification and record keeping requirements (40 CFR 60.7), compliance with standards and maintenance requirements (40 CFR 60.11), and the monitoring requirements (40 CFR 60.13) for each affected source.

3.3.2.2 Combined Cycle Units

NSPS for combined cycle units are covered in 40 CFR 60 and potentially include: Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978; in 40 CFR 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; and in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines. Because the steam generators associated with Power Block 2 (i.e., HRSGs) will utilize only the waste heat from the combustion turbines, only the requirements of Subpart GG and Subpart A will apply.

Subpart GG regulates the CC units as electric utility stationary gas turbines and establishes emission limitations on both NO_x and SO_2. The NO_x emission limitation is set by the following equation:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_X emission allowance for fuel-bound nitrogen as defined below:

Fuel-bound nitrogen (percent by weight)	F (NO_X percent by volume)
N<0.015	0
0.015<N<0.1	0.04(N)
0.1<N<0.25	0.004 + 0.0067(N-0.1)
N>0.25	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

This results in an emission limitation of 113.5 parts per million on a dry volume basis (ppmvd) at 15 percent oxygen for the proposed units when fired on natural gas and 112.7 ppmvd at 15 percent oxygen when fired on fuel oil. (These values do not include the allowance for fuel-bound nitrogen). The SO_2 emission limitations are set at 150 ppmvd corrected to 15 percent oxygen in the exhaust stream or a fuel sulfur content less than or equal to 0.8 percent by weight.

40 CFR 60 Subparts Da, Db, and Dc are not applicable to the CC units since the HRSGs will not be fired with any type of auxiliary fuel.

3.3.2.3 Excess Emissions

The EPA has adopted general and specific recordkeeping and reporting requirements relating to excess emissions in 40 CFR 60.7(b) and 40 CFR 60.334(c). The EPA requirements specify maintaining records and submittal of a quarterly report (calendar year) on excess emissions associated with start-ups, shutdowns, malfunctions, inoperative continuous emission monitoring systems, low water-to-fuel ratio, and fuel sulfur content greater than 0.8% by weight. The reporting requirement includes submittal of the quarterly report even when no excess emissions occur. EPA has not adopted any specific time limits related to excess emissions from a CC unit, or from combustion turbine units regulated under 40 CFR Part 60, Subpart GG.

3.3.3 State-Specific and General Emission Standards

In addition to federal requirements, FDEP has adopted specific and general emission limiting and performance standards. These standards may be found in Rule 62-296, F.A.C. The requirements of these standards must be met along with any federal PSD or NSPS limitation or requirement.

3.3.3.1 General Emission Standards

The FDEP has adopted general particulate matter emission limits as well as general pollutant emission limits (Rule 62-296.320, F.A.C.). These limits apply when no specific emission standard is applicable.

3.3.3.2 Combined Cycle Units

The FDEP has not adopted any state-specific emission standards in Rule 62-296, F.A.C. relating to the operation of a CC unit. The FDEP has adopted the NSPS requirements of Subparts A and GG by reference in Rule 62-204.800, F.A.C. Based on the current FDEP rules, the CC units must meet the NSPS requirements as discussed in Section 3.3.2.2. In addition, a general opacity limit of less than 20 percent and a prohibition on emitting air pollutants that cause or contribute to an objectionable odor apply.

3.3.3.3 Excess Emissions

The FDEP has adopted standards relating to excess emissions in Rule 62-210.700, F.A.C. The rule allows excess emissions resulting from startup, shutdown, or malfunction of any source as long as best operational practices are applied and the excess emissions do not exceed 2 hours in any 24 hour period. Currently, the rule allows one exception from the 2 hour limit and that is for existing fossil fuel steam generators. The FDEP can authorize different excess emission parameters for other sources on a case-by-case basis.

Based on the intended operation of the CC units, FPC requests that the FDEP consider the operational variations of this equipment as well as the EPA's NSPS requirements on excess emissions and set an allowable excess emissions level for Power Block 2 as follows:

> "Excess emissions from a combined cycle unit resulting from startup, shutdown, fuel switch, or malfunction shall be permitted for up to four (4) hours provided that best operational practices to minimize excess emissions are adhered to and the duration of the excess emissions shall be minimized."

3.4 SOURCE APPLICABILITY

3.4.1 Pollutant Applicability

The PSD regulations apply to the proposed generation project due to the attainment status for the Polk County Site. Polk County and the surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The Polk County Site is located approximately 118 km southeast of the Chassahowitzka National Wilderness Area (NWA), the nearest PSD Class I area. The Chassahowitzka NWA is that portion of the Chassahowitzka National Wildlife Refuge which has been officially designated as wilderness.

Pollutant applicability for the proposed facilities is addressed in Sections 2.0 and 4.0 and briefly summarized here. The proposed Power Block 2 project is considered to be a modification to an existing major source under the PSD regulations. PSD review is required for any regulated pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 2-5. As shown, the potential emissions for the proposed facilities will exceed the PSD significant emission rates for the following regulated pollutants: CO, NO_X, SO_2, PM_{10}, VOC, and sulfuric acid mist. The proposed project is subject to PSD review for these pollutants.

3.4.2 Ambient Air Quality Monitoring

Based upon the net increase in emissions from the proposed facility presented in Table 2-3, a PSD preconstruction ambient air monitoring analysis is required, as part of the air quality impact analysis for CO, NO_2, SO_2, PM_{10}, O_3 (based on VOC emissions), and sulfuric acid mist. However, if the net increase in a source's impact of a pollutant is less than the *de minimis* air quality impact level, as shown in Table 3-2, then preconstruction ambient air quality monitoring is not required for that pollutant. In addition, if an acceptable ambient air monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Preliminary Dispersion modeling was performed to determine those pollutants which could be exempted from the monitoring requirement. As verified by the revised modelling analysis described in Sections 6.0 and 7.0, the increases in air quality impacts are predicted to fall below the *de minimis* impact levels presented in Table 3-2, therefore, pre-construction monitoring is not required. The results for these pollutants are presented in Section 5.0.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels

Pollutant	Averaging Time	AAQS (μg/m³) Primary Standard	AAQS (μg/m³) Secondary Standard	AAQS (μg/m³) Florida	PSD Increments (μg/m³) Class I	PSD Increments (μg/m³) Class II	Significant Impact Levels (μg/m³) [b]
Particulate Matter[c] (PM10)	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	8-Hour Maximum[c]	157	157	157	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year.

[b] Maximum concentrations are not to be exceeded.

[c] 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm or less.
FDEP has not yet adopted these standards.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-272, F.A.C.

Table 3-2. PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] (μg/m³)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	3.5×10^{-6}	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

NAAQS = National ambient air quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
g/m³ = Micrograms per cubic meter.
MWC = Municipal waste combustor.
MSW = Municipal solid waste.

[a] Short-term concentrations are not to be exceeded.
[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.
[c] Any emission rate of these pollutants.

Sources: 40 CFR 52.21.
Rule 62-212.400

4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

4.1 INTRODUCTION

This section of the PSD application provides a detailed BACT analysis for the Hines Energy Complex Power Block 2 installation of approximately 530 MW of combined cycle (CC) generation. The CC units will consist of two CTs, two HRSGs, and one steam turbine, termed a "two-on-one" configuration.

The project's potential annual emissions of the following regulated pollutants exceed the PSD significant emission rate thresholds and are, therefore, subject to BACT review:

- Carbon Monoxide (CO)
- Nitrogen Oxides (NO_X)
- Sulfur Dioxide (SO_2)
- Particulate Matter (PM/PM_{10})
- Volatile Organic Compounds (VOC)
- Sulfuric Acid Mist (H_2SO_4)

This BACT analysis assumes that two CT units will be operating at an annual average inlet temperature of 59°F and an ambient relative humidity of 60 percent. These compressor inlet conditions represent a conservative estimate of annual average emissions, and account for the potential use of inlet cooling for the two CTs. In order to assure that conservatively high pollutant emission rates are used in the BACT analysis, the CT units are assumed to operate for 8,760 hours per year. For evaluating BACT for NO_x, natural gas firing is assumed for 7,760 hours at 100 percent load and distillate oil firing for 1,000 hours at 100 percent load (an aggregate of 29,365,000 gallons per year based on 1,000 hours of operation per year for each CTs at full load) for evaluating BACT for CO.

4.2 METHODOLOGY

This BACT analysis follows the general requirements of EPA's draft "top down" BACT guidance document (EPA, 1990c), which requires that the BACT analysis start by assuming the use of the most stringent control technology. Sources of information which were used to identify control alternatives include:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) via the RBLC Information System database;
- Recent FDEP BACT determinations for similar facilities;
- Vendor information; and
- Florida Power Corporation (FPC) experience for similar projects.

Of the control alternatives identified, the less efficient alternatives are evaluated if the most stringent control technology is determined to be technologically infeasible or unreasonable considering economic, energy, and environmental factors. The economic analyses in this section are based on the procedures found in the Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (EPA, 1990b).

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

As indicated in Section 2.2, Table 2-3, projected annual emission rates of NOx, CO, VOCs, PM/PM10, SO2, and H2SO4 mist for Power Block 2 exceed the PSD significance rates and, therefore, are subject to a BACT analysis. Control technology analyses using the top-down BACT method are contained in Section 4.4 for combustion products (PM/PM10), Section 4.5 and 4.6 for products of incomplete combustion (CO and VOCs, respectively), and Sections 4.7 and 4.8 for acid gases (NOx ,and SO2 and H2SO4 mist, respectively).

4.3 STATE AND FEDERAL EMISSION STANDARDS

This section provides a summary of potentially applicable emission standards at the state and federal level. The BACT emission limitations proposed for the Hines Energy Complex Power Block 2 are all more stringent than the applicable federal and state standards cited in the following summary.

FDEP emission standards for stationary sources are contained in Chapter 62-296, Stationary Sources-Emission Standards, F.A.C. This chapter contains general emission standards for sources emitting PM (Rule 62-296.320, F.A.C.) that are applicable to the Project. Visible emissions are limited to a maximum of 20 percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Emission standards applicable to sources located in non-attainment areas are contained in Rules 62-296.500 (for ozone areas) and 62-296.700, F.A.C. (for PM non-attainment areas). Because Power Block 2 is located in Polk County, Florida, and because this county is designated attainment for all criteria pollutants, these emission standards are not applicable. Finally, Rule 62-204.800, F.A.C., adopts federal New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS), respectively, by reference.

On the federal level, NSPS Subpart GG establishes emission limits for gas turbines that meet certain criteria. The Power Block 2 CTs qualify as electric utility stationary gas turbines and, therefore, are subject to the NOx and SO2 emission limitations of NSPS 40 CFR 60, Subpart GG, § 60.332(a)(1) and § 60.333, respectively. The proposed Hines Energy Complex Power Block 2 has no applicable NESHAP requirements. In addition, the total emissions of hazardous air pollutants (HAPs) are less than 10 tons per year for any single HAP and less than 25 tons per year for all HAPs. Therefore, mamimum achievable control technology (MACT) review is not required.

4.4 BACT ANALYSIS FOR PM/PM_{10}

4.4.1 Potential Control Technologies

Several control technologies commonly used to limit emissions of PM include baghouses, electrostatic precipitators (ESPs), wet scrubbers and mechanical collectors. The NSPS for CT units does not establish an emission limit for particulate matter. Further, a review of RBLC documents did not reveal any post-combustion particulate matter control technologies being used on CC units. All determinations were based on the use of clean fuels and good combustion practice.

The natural gas fuel to be used in the proposed CT units will contain only trace quantities of noncombustible material. The use of low sulfur fuel oil, as a back-up fuel, will be limited. In addition, the CTs proposed for Power Block 2 will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM10 emission rates. In fact, the manufacturer's standard operating procedures will ensure as complete combustion of the fuel as possible.

4.4.2 Proposed BACT Emission Limitations

Based on the above analysis, it is proposed that BACT for PM/PM10 emissions from the CTs be the use of good combustion practices and clean fuels. The CTs will be fired primarily with natural gas, with limited low sulfur fuel oil backup capability. FPC requests that the use of fuel oil be limited to no more than 27,365,000 gallons per year. This requested quantity is consistent with the current permit limit for Power Block 1 and is based on an aggregate of 2,000 hours per year of operation between the two CTs at full load and 59°F. Since the only technically feasible alternative is proposed to be BACT, an economic and environmental analysis is not required and is not presented.

Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM10 concentrations and consistent with recent FDEP BACT determinations for CTs, a visible emissions limit of 10/20 percent opacity for natural gas/fuel oil is proposed as a surrogate BACT limit for PM/PM10.

4.5 BACT ANALYSIS FOR CO

Carbon monoxide (CO) emissions result from the incomplete combustion of carbon and organic compounds. CTs have inherently low CO emissions, which are categorized as products of incomplete combustion of fossil fuels. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize CO emissions. Therefore, formation of CO is a function of the manufacturer's combustor design. Because lower combustion temperatures will result in a decrease in oxidation rates, emissions of CO will generally increase during turbine partial load conditions when combustion temperatures are lower.

4.5.1 Potential Control Technologies

A search of the RBLC was conducted for CO control determinations for natural gas fired CTs. A summary of the results is presented in Table 4-1. There are two available technologies for controlling CO from gas turbines: (1) combustion process design and good combustion practices and (2) oxidation catalysts.

4.5.1.1 Combustion Process Design

A combustor design based on high combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize CO emissions. Therefore, this control alternative is based on combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTs, CO emissions are inherently low.

4.5.1.2 Oxidation Catalysts

The oxidation catalyst process is based on a straight catalytic reaction requiring no additives. The reactions and catalysts used (platinum based) are similar to the catalytic oxidation technology used for automotive emission control. Products from the reaction include carbon dioxide and water. Catalytic oxidation systems are capable of CO reductions of between 50 and 80 percent. However, this reduction potential will be greater with higher initial concentrations of the pollutants.

4.5.1.3 Technical Feasibility

Combustion process design is considered to be technically feasible for the proposed CTs. Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica, which are present in fuel oil, will all act as catalyst contaminants causing a reduction in catalyst activity and removal efficiencies. In spite of this, the addition of an oxidation catalyst was considered to be technically feasible for this BACT analysis. Significant CO oxidation will occur at any temperature above roughly 500°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and removal efficiencies. Exhaust gas temperatures associated with the proposed project are within this performance range. Information regarding energy, environmental, and economic impacts of an oxidation catalyst for CO are provided in the following sections.

4.5.2 Energy and Environmental Impacts

There are no significant adverse energy or environmental impacts associated with the use of good combustion designs and operating practices to minimize CO emissions.

A catalyst that oxidizes CO to CO_2 will also oxidize SO_2 to SO_3. While firing fuel oil, 5 percent of the SO_2 in the flue gas will be converted to SO_3. When the SO_3 comes in contact with moisture, it will form sulfuric acid mist (H_2SO_4) that can cause corrosion damage to downstream plant equipment and damage to surrounding vegetation. H_2SO_4 created will also increase particulate emissions from the facility. Because CO emission rates from CTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements, i.e., impacts are already well below the defined PSD significant impact levels for CO. The location of the Hines Energy Complex (Polk County, Florida) is classified attainment for all criteria pollutants. Modeling of CO emissions from the Project indicate that the maximum CO impacts, without oxidation catalyst, will be many times lower than the EPA and FDEP significant impact levels; there would be no air quality benefit with the addition of an oxidation catalyst to reduce the already low CO emissions.

Although CO has been well documented as a criteria pollutant, significant international pressure is now being exerted to reduce CO_2 emission levels in response to the suspected contributions of the gas to global warming. A CO oxidation catalyst could increase the CO_2 emissions from each unit by almost 442 pounds per hour (1,934 TPY assuming 8,760 hours per year of operation).

The application of an oxidation catalyst would result in a derate of approximately 0.2 percent (0.36 MW) of CT output. Since power demand will remain constant, this derate will be replaced by a combustion source that has higher CO emissions than the planned units at the Hines Energy Complex. Further the pressure drop across the catalyst bed and resulting increase in the unit's heat rate results in a potential energy loss of 30,543 MMBtu per year per CT of natural gas. This is equivalent to the use of about 31 million cubic feet (ft^3) of additional natural gas annually.

4.5.3 Economic Impacts

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors and project-specific vendor information. Capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 4-2 and 4-3, respectively.

The capital costs for the catalytic reduction system include the costs of the catalytic reactors and balance of plant equipment. Capital costs for the catalytic emission reduction system are based on budgetary quotations from equipment manufacturers. Annual operating costs include maintenance (predominantly catalyst replacement) and lost generation due to the pressure drop across the catalyst. The total capital cost for installation of the oxidation catalyst control system is estimated to be approximately $1,675,200 per CT. The total annualized cost is estimated to be approximately $712,400. The cost effectiveness (incremental emission reduction cost) of the oxidation catalyst was determined to be $2,130 per ton of CO removed. This cost-effectiveness value is conservatively low due to the the conservative operation assumptions and is in the range that has typically not been deemed BACT for CO by DEP.

4.5.4 Proposed BACT Emission Limitations

The use of oxidation catalysts to control CO emissions from CTs have been generally installed on facilities located in CO non-attainment areas. The use of combustion controls results in CO emission rates from the proposed CTs that are inherently low and in the range established as BACT for similar sources in attainment areas. As discussed in the preceding paragraphs, there are also significant energy and environmental impacts associated with the use of this technology. Further reductions through the use of oxidation catalysts will result in no measurable benefit in air quality.

Use of state-of-the-art combustion design and good operating practices to minimize incomplete combustion are proposed as BACT for CO emissions. For all CT projects recently permitted by the FDEP, these control techniques have been considered by FDEP to represent BACT for CO emissions. Therefore, at base load operation, the proposed BACT for CO emissions from the CTs will be 10 ppmvd at 15 percent O_2 (42 lb/hr at 59 °F compressor inlet conditions) for natural gas and 30 ppmvd (106 lb/hr at 59°F) for fuel oil, respectively. At 60 percent load while firing natural gas, emissions will not exceed 50 ppmvd at 15 percent O_2 (146 lb/hr at 59 °F).

4.6 BACT FOR VOCs

A small amount of VOCs will be emitted by the CT as a result of incomplete combustion. The control technology established as BACT in Florida has been overwhelmingly the use of combustion controls and clean fuels. The proposed BACT emission levels when firing natural gas are 1.8/3.0 ppmvd at 15 percent O_2 (4.4/5.0 lb/hr at 59 °F compressor inlet conditions) for 100 percent and 60 percent loads, respectively. When firing distillate oil, the proposed BACT emission rate is 10 ppmvw (21 lb/hr at 59 °F). These levels are within the BACT levels recently established for other similar sources. Moreover, at these low concentrations, the application of control technologies, such as oxidation catalysts, are uncertain. The environmental benefit of further reducing the amount of VOCs from the combustion turbines proposed for Power Block 2 would be insignificant.

4.7 BACT ANALYSIS FOR NO_x

During combustion, two types of NO_X are formed: thermal NO_X and fuel NO_X. Thermal NO_X emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. Formation of nitrogen oxides through thermal NO_X can be limited by lowering combustion temperatures by staging combustion (a reducing atmosphere followed by an oxidizing atmosphere), or by post-combustion controls. Fuel NO_x arises from the oxidation of non-elemental nitrogen contained in the fuel. The conversion of fuel-bound nitrogen (FBN) to NO_x depends on the bound nitrogen content of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion process or fuel treatment technologies available to control fuel NO_x emissions. For this reason, the gas turbine NSPS (Subpart GG) contains an allowance for FBN above 0.015 percent (see Section 4.3). NO_x emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion temperatures and FBN contents. Natural gas may contain molecular nitrogen (N_2); however the N_2 found in natural gas does not contribute significantly to fuel NO_x formation. Typically, natural gas contains a negligible amount of FBN.

4.7.1 Potential Control Technologies

A review of the latest control technology determinations (RBLC summary in Table 4-4) indicates that the lowest NO_x emission limits established to date for a CC unit equipped with a dry low NO_x combustor in EPA Region IV ranges from 3.5 to 4 ppmvd corrected to 15 percent O_2. This is for a natural gas-fired combined cycle (CC) unit and was based on the use of dry low NO_x combustors operating within a CT that can achieve 9 to 15 ppmvd in combination with a selective catalytic reduction (SCR) system achieving from 60 to 70 percent NO_x removal. Therefore, the most stringent control technology for NO_x emissions control with a CC unit using dry low NO_x combustors is an SCR system. Recent FDEP natural gas-fired CT NO_x BACT determinations of 9 ppmvd at 15 percent O_2 with dry low NO_x combustors and with levels ranging from 3.5 to 7.5 ppmvd at 15 percent O_2 with SCR. For oil firing, the BACT emission rate established by FDEP was 15 ppmvd at 15 percent O_2 using water injection and SCR.

Available technologies for controlling NO_x emissions from CTs include combustion process modifications and post-combustion exhaust gas treatment systems, as follows:

Combustion Process Modifications:

- Water/steam injection and good combustor design.
- Dry low- NO_x combustor design/XONON™ catalytic combustor.

Post-Combustion Exhaust Gas Treatment Systems:

- Selective Catalytic Reduction (SCR).
- Selective Non-Catalytic Reduction (SNCR).
- SCO NO_x™

A description of each of the listed control technologies is provided in the following sections.

4.7.1.1 Water or Steam Injection and Good Combustor Design

Use of water or steam injection in the combustion zone of a CT unit can limit the amount of NO_X formed. Thermal NO_X formation is avoided due to lower combustion temperatures resulting from the water or steam injection. The degree of reduction in NO_X formation is somewhat proportional to the amount of water or steam injected into the turbine. Further, high purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades.

Since the CT unit NSPS for NO_X was last revised, CTs have improved their tolerance to the water or steam necessary to control the NO_X emissions below the current NSPS level. However, there is still a point at which the amount of water or steam injected into the turbine seriously degrades the turbine's reliability and operational life. With the manufacturers' existing turbine designs and standard combustors, this generally occurs below a NO_X emission level of about 25 ppmvd when firing natural gas and 42 ppmvd when firing fuel oil in conventional combustion turbines. For the larger "F" class combustion turbines, wet injection has been used to achieve a level of 42 ppmvd when firing natural gas (i.e., FPL Lauderdale Repowering Project).

The advanced combustor designs available for Power Block 2 will be capable of achieving low NO_X emissions without the use of water or steam injection (dry) while firing natural gas. Considering the water use issues prevalent in Florida, dry low NO_X combustion controls are preferred. This analysis disregards further consideration of wet NO_X control CTs when natural gas is used.

4.7.1.2 Dry Low NO_x Combustor Design/ XONON™ Catalytic Combustor

CT manufacturers have committed that their future technology will support lower NO_X emissions without water injection on natural gas. Dry low NO_x combustors premix turbine fuel and air prior to combustion in the primary zone resulting in a homogeneous air/fuel mixture. For this reason, the peak and average flame temperature are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner. The more recent designs are operated in total premix mode, but require a load transition to achieve optimal performance. Total premix mode generally occurs in the 50 to 65 percent load range. Currently, premix burners are limited in application to natural gas and loads above approximately 50 percent due to flame stability considerations.

During oil firing, water or steam injection is employed to control NO_x emissions. The Siemens Westinghouse dry low NO_x combustor design currently available is capable of combustor-controlled NO_x emissions of 25 ppmvd while burning natural gas. Fuel oil burning requires water injection and has NO_x emissions of 42 ppmvd. Fuel oil burning will be limited to no more than 27,365,000 gallons per year, based on an aggregate of 2,000 total hours per year between the two CTs at full load and is expected to have only a minor impact on water usage.

Catalytic combustors are being developed for low emission applications on turbines where the catalyst is internal to the combustion system. The XONON™ Combustion System is a catalytic combustion system developed by Catalytica Combustion Systems, Inc. which can achieve low emission levels of NO_x, CO and VOC. The XONON™ system combusts the fuel over a catalyst, reducing the temperature of combustion and providing for more complete combustion of the fuel. The system is referred to as "flameless combustion", where combustion temperatures are at conditions where limited NO_x formation occurs. However, the exhaust temperatures from a combustion turbine standpoint are still sufficient for the expansion of the gases through the turbine for power generation. Emission levels of NO_x at less than 2 ppm have been reported for the 1.5 MW Kawasaki gas turbine located at Sun Valley Power. Recently, this technology has been proposed for a 750 MW combined cycle facility. This facility, the Pastoria Energy Facility, is a project proposed by affiliates of Enron Corporation, which has a 15 percent interest in Catalytica Combustion Systems, Inc. Commercial operation is scheduled for the summer of 2003. Catalytica is currently working in collaboration with several gas turbine manufacturers including General Electric, Pratt & Whitney, Rolls Royce Allison and Solar. XONON™ is not considered technically feasible based on the lack of operating experience with "F" Class turbines.

4.7.1.3 Selective Catalytic Reduction

SCR is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The following primary reactions take place:

$$4NH_3 + 4NO + 0_2 \Rightarrow 4N_2 + 6H_20 \quad (1)$$
$$4NH_3 + 2N0_2 + 0_2 \Rightarrow 3N_2 + 6H_20 \quad (2)$$

The performance and effectiveness of SCR systems is directly dependent on catalyst operating temperatures. The optimum temperature range for SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (1) and (2) above will not proceed, resulting in large quantities of ammonia slip. At temperatures exceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in NO_x emissions. At temperatures above about 800°F, permanent damage to the catalyst occurs. NO_x removal efficiencies for SCR systems typically range from 70 to 90 percent.

Flue gas from a CT will typically range from 950°F to 1,100°F. Accordingly, an SCR device would be installed at an intermediate point of the HRSG after several rows of tubes, where a temperature of approximately 700°F occurs. The narrow SCR temperature window dictates that the SCR catalyst be precisely located in the HRSG. A recent report indicated that effective SCR operation becomes very difficult for units that see a variation in gas flow and temperature through the HRSG due to load changes or ambient temperature swings (Boericke, 1990). Another report indicates that maintaining the catalyst in the narrow SCR temperature window over the entire CC unit operating load range can be difficult (Shorr, 1991). Therefore, SCR performance will be difficult to maintain to very low NO_x levels if the CC unit load varies or if significant temperature swings occur. For the proposed Power Block 2, CT operation will be within 60 to 100 percent load where DLN NO_x reductions are consistent.

Catalyst NO_X reduction efficiency will be affected by the NO_X concentration at the SCR inlet. The reaction mechanism requires both NO_X and ammonia to occupy a catalytic reaction site at the same time. This is a random event. The lower the NO_X concentration, the less likely it is that any one ammonia gas molecule and NO_X gas molecule will meet on a reaction site. Therefore, as the SCR inlet concentration of NO_X decreases, the catalyst needs to become larger and/or the amount of ammonia added needs to be increased (leading to increased ammonia slip) for similar NO_X reduction efficiencies. The dry low NO_X combustors have relatively low NO_X emissions and will therefore require a greater volume of catalyst than a standard combustor would for the same NO_X removal efficiency.

Catalyst NO_X reduction efficiency also will be affected by the type of fuel being burned. When firing fuel oil, the SCR catalyst can oxidize up to 10 percent of the SO_2 in the flue gas to SO_3. Catalytic reduction efficiency is therefore reduced when available reaction sites are occupied by sulfur compounds. Additionally, the ammonia present in the flue gas will react with the SO_3 to form ammonia sulfate salts and the water in the flue gas will react with the SO_3 to form sulfuric acid mist. The formation of ammonia sulfate salts will reduce the amount of ammonia available for reaction with the NO_X. Ammonium bisulfate, one of the ammonia salts formed, will also reduce a CC unit's thermal efficiency by coating the heat transfer surfaces of the HRSG and potentially limit unit availability due to forced outages for HRSG cleanup. Both the ammonia sulfate salts and the sulfuric acid mist will increase the amount of particulate matter emitted in the flue gas to a level of approximately 20 lbs/hr per CT in the form of ammonium salts. This particulate will predominately consist of matter less than 10 microns in size (PM_{10}).

Catalyst life expectancy also can be affected by the type of fuel burned. Catalyst poisoning can be caused by such trace elements as arsenic, beryllium, cadmium, chromium, copper, lead, manganese, mercury, and nickel, all of which can be found in fuel oil at low concentrations. Arsenic, the major poison, can be deposited on catalyst surfaces in the form of gaseous arsenic oxide, which can clog the small pores of the catalyst and prevent the ammonia/nitrogen oxide mixture from being catalytically oxidized.

4.7.1.4 Selective Non-Catalytic Reduction

Nitrogen oxide emissions from other types of combustion sources also have been controlled through installation of selective noncatalytic reduction (SNCR) systems such as Thermal $DeNO_X$ and NO_XOUT. Chemical reactions for the Thermal $DeNO_x$ process are as follows:

$$4NO + 4NH_3 + 0_2 \Rightarrow 4N_2 + 6\,H_20 \qquad (3)$$
$$4\,NH_3 + 5\,0_2 \Rightarrow 4NO + 6\,H_20 \qquad (4)$$

The NO_xOUT process is similar with the exception that urea is used in place of NH_3. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted NH_3 to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor Reaction (3), resulting in a reduction in NO_x emissions. Reaction (4) will dominate at temperatures above approximately 2,000°F causing an increase in NO_x emissions. Temperatures below 1,300°F result in ammonia slipping through the system unreacted without any corresponding reduction in NO_X emissions. As reported earlier, the temperature at the outlet of a CT unit utilizing dry low NO_X combustors, is too low (950°F to 1,100°F) for such a system. Accordingly, this alternative is judged not to be technically feasible for application on a CC unit.

4.7.1.5 SCONO$_x$™

SCONO$_x$™ is a NO_x and CO control system exclusively offered by Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc. For turbines of 100 MW and larger, ABB Environmental has the license for the technology.

The SCONO$_x$™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The SCONO$_x$™ oxidation/absorption cycle reactions are:

$$CO + 1/2\ O_2 \Rightarrow CO_2 \qquad (5)$$
$$NO + 1/2\ O_2 \Rightarrow NO_2 \qquad (6)$$
$$2NO_2 + K_2CO_3 \Rightarrow CO_2 + KNO_2 + KNO_3 \qquad (7)$$

CO_2 produced by reaction (5) and (6) is released to the atmosphere as part of the CT/HRSG exhaust gas stream.

As shown in Reaction (7), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The SCONO$_x$™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4\ H_2 + CO_2 \Rightarrow K_2CO_3 + 4\ H_2O_{(g)}) + N_2 \qquad (8)$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the

CT/HRSG exhaust stream. Following regeneration, the $SCONO_x$™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 75 percent of the catalyst sections will be in the oxidation/absorption cycle, while 25 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 5 minutes.

Regeneration gas is produced by reacting natural gas with O_2 present in ambient air. The $SCONO_x$™ system uses a gas generator produced by Surface Combustion. This unit uses a two-stage process to produce hydrogen and carbon dioxide. In the first stage, natural gas and ambient air are reacted across a partial oxidation catalyst at 1,900°F to form CO and hydrogen. Steam is added and the gas mixture is then passed across a low temperature shift catalyst, forming CO_2 and additional hydrogen. The resulting gas stream is diluted to less than 4 percent hydrogen using steam or another inert gas. The regeneration gas reactions are:

$$CH_4 + 1/2\ O_2 + 1.88\ N_2 \Rightarrow CO + 2\ H_2 + 1.88\ N_2 \qquad (9)$$

$$CO + 2\ H_2 + H_2O + 1.88\ N2_2 \Rightarrow CO_2 + 3\ H_2 + 1.88\ N_2 \qquad (10)$$

The $SCONO_x$™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For $SCONO_x$™ systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the $SCONO_x$™ catalyst that reforms the natural gas.

The $SCONO_x$™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system ($SCOSO_x$™) to remove sulfur compounds is installed upstream of the $SCONO_x$™ catalyst. During regeneration of the $SCOSO_x$™ catalyst, either hydrogen sulfide or SO_2 is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the $SCOSO_x$™ process is proprietary. $SCOSO_x$™ oxidation/absorption and regeneration reactions are:

$$CO + 1/2\,O_2 \Rightarrow CO_2 \tag{11}$$
$$SO_2 + 1/2\,O_2 \Rightarrow SO_3 \tag{12}$$
$$SO_3 + \text{SORBER} \Rightarrow [SO_3 + \text{SORBER}] \tag{13}$$
$$[SO_3 + \text{SORBER}] + 4\,H_2 \Rightarrow H_2S + 3\,H_2O \tag{14}$$

Utility materials needed for the operation of the $SCONO_x$™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the $SCONO_x$™ control system is limited to one small combined cycle (CC) power plant located in Los Angeles. This power plant, owned by GLET partner Sunlaw Energy Corporation, utilizes a GE LM2500 turbine equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The $SCONO_x$™ control system was installed at the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 ppmv resulting in an approximate 85 percent NO_x removal efficiency.

A second $SCONO_x$™ system was installed at the Genetics Institute Facility in Andover, Massachusetts in late 1998. The system is installed on a 5-MW Caterpillar Solar Turbine with a Deltak boiler. The NO_x emission limit is 2.5 ppmvd at 15-percent O_2. ABB Environmental reports that the system is operating successfully, although there have been incidents of high NO_x emissions that ABB Environmental attributes to combustion control problems and not to the $SCONO_x$™ system.

The $SCONO_x$™ control technology is not considered to be technically feasible because it has not been commercially demonstrated on large CTs. The CTs planned for the Hines Power Block 2 project, Siemens-Westinghouse 501F units, each have a nominal generating capacity of 170 MW which are approximately seven times larger than the nominal 25-MW GE LM2500 utilized at the Sunlaw Energy Corporation federal facility.

Technical issues associated with scale-up of the $SCONO_x$™ technology given the large differences in machine flow rates may be significant.

4.7.1.6 Technical Feasibility

All of the combustion process control technologies presented above (i.e., water/steam injection for oil firing and dry low NO_x combustor design for gas firing) would be potentially feasible for the Power Block 2 CTs. Of the post-combustion stack gas treatment technologies, SNCR is not feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in CT exhaust gas streams (approximately 1,000°F). The XONON™ catalytic combustion technology and $SCONO_x$™ control technology are not considered to be feasible because they have not been commercially demonstrated on large CTs. The CTs planned for the Hines Energy Complex Power Block 2, Siemens Westinghouse 501 FD units, each have a nominal generating capacity of 170 MW which are approximately six times larger than the nominal 25-MW GE LM2500 utilized at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the $SCONO_x$™ technology given the large differences in machine flow rates are unknown. Additional concerns with the $SCONO_x$™ control technology include process complexity (multiple catalytic oxidation / absorption / regeneration systems), reliance on only one supplier, and the relatively brief operating history of the technology.

The BACT analysis for NO_x for the Power Block 2 CTs evaluated the use of dry low NO_x combustors available from Siemens Westinghouse and the application of post-combustion SCR control technologies. The dry low NO_x combustors are expected to achieve 25 ppmvd corrected to 15 percent oxygen when firing natural gas and with water injection achieve 42 ppmvd corrected to 15 percent oxygen when firing distillate oil. Steam/water injection technology for natural gas firing was not evaluated because it results in NO_x emissions that are higher than those achieved by dry low NO_x combustor technology and has associated water use and lower heat rate considerations. Also, the water consumption and sludge treatment/disposal requirements associated with water/steam injection do not exist for dry low-NO_x combustors, making dry low NO_x combustor technology preferable to wet injection as the primary control for natural gas firing. The SCR system was evaluated based on achieving a NO_x concentration of 3.5 ppmvd corrected to 15 percent oxygen when firing only natural gas. This represents a control efficiency of about 86 percent which is at the upper ranges of removal efficiencies established as BACT with SCR. Information regarding energy, environmental, and economic impacts and proposed BACT limits for NO_x are provided in the following sections.

4.7.2 Energy and Environmental Impacts

The use of advanced dry low NO_x combustor technology will not have a significant adverse impact on CT heat rate.

The installation of SCR technology will cause an increase in back pressure on the CTs due to the pressure drop across the catalyst bed. The back pressure would also increase with the installation of additional catalyst volume. Higher NOx removal will require additional catalyst volume resulting in greater energy penalty. The energy penalty would be approximately 0.3 percent for SCR installed on Power Block 2. Additional energy will be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. Energy penalty due to CT back pressure is projected to be 4,730,400 kwh per year for each CT while reducing NOx to 3.5 ppmvd corrected to 15 percent oxygen. The total SCR energy penalty including dilution air fans is estimated to be 5,431,200 kwh per year for each CT which is equivalent to an energy loss of 52,600 MMBtu/yr. This is equivalent to the use of about 53 million ft^3 of natural gas annually based on a gas heating value of 1,000 Btu per ft^3.

There are no significant adverse environmental effects due to the use of advanced dry low NO_x combustor technology. Application of SCR technology results in the following environmental impacts:

- NH_3 emissions due to *ammonia slip*; NH_3 emissions are estimated to total 112 tpy (at base load and 59°F ambient temperature) for a typical SCR design and an ammonia slippage rate of 9 ppmvd at the 15 percent O_2 for each CT. Ammonia slip is much lower during the early stages of catalyst usage and increases with age. Increasing efficiency, such as reducing the already low exhaust NO_x emissions of 3.5 ppm to a lower level can also potentially increase ammonia slip. This is especially true because the SCR design is already at the upper range of its maximum reduction efficiency.
- Ammonium bisulfate and ammonium sulfate particulate emissions due to the

reaction of NH_3 with SO_3 present in the exhaust gases; as a result, total particulate matter emissions would increase. This effect is more of a concern when firing oil. The emission rates for both gas and oil accounted for additional formation of particulate due to the reaction of NH_3 and SO_3.

4.7.3 Economic Impacts

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced dry low NO_x combustor technology and baseline technology with the addition of SCR controls. As supplied by Siemens Westinghouse, the 501 FD unit is equipped with dry low NO_x combustors. Siemens Westinghouse does not offer any other option with respect to combustor type or design. Dry low-NO_x technology provided by Siemens Westinghouse is expected to achieve a NO_x exhaust concentration of 25 ppmvd at 15 percent O_2. SCR technology was premised to achieve NO_x concentrations of 3.5 ppmvd at 15 percent O_2 for natural gas firing and 15 ppmvd at 15 percent O_2 for oil firing. The NO_x concentration of 3.5 ppmvd is representative of the maximum NO_x removal efficiencies determined as BACT for natural gas fired CTs equipped with dry low NO_x combustor technology and SCR controls.

The cost impact analysis was conducted using the OAQPS factors and project-specific vendor estimate. Emission reductions were calculated assuming base load operation for 8,760 hr/yr at an annual average ambient temperature of 59°F (7,760 hours of gas firing and 1,000 hours of oil firing). Specific capital and annual operating costs for the SCR control system are summarized in Tables 4-5 and 4-6, respectively.

Cost effectiveness for the applicat ion of SCR technology to the Hines Energy Complex Power Block 2 for natural gas firing was determined to be \$2,610 per ton of NO_x removed. This control cost is for an SCR system achieving NO_x levels of 3.5 ppmvd at 15 percent oxygen while firing natural gas with an initial NO_x level of 25 ppmvd using dry low NO_x combustor technology available from Siemens Westinghouse and 15 ppmvd at 15 percent O_2 while firing distillate oil with an intial NO_x level of 42 ppmvd at 15 percent O_2 using water injection. Achieving NO_x levels of 3.5/15 ppmvd at 15 percent oxygen while firing natural gas and oil, respectively, results in a NO_x reduction of 823 tons/year (at 100 percent load).

4.7.4 Proposed BACT Emission Limitations

NO_x BACT emission limits proposed for the Hines Energy Complex Power Block 2 CTs, are based on the application of dry low NO_x combustors achieving NOx levels to 25 ppmvd (load-weighted) and an SCR system achieving 3.5 ppmvd at 15 percent O_2, 24-hour block weighted average, for gas firing and 15 ppmvd at 15 percent O_2, 24-hour block weighted average for oil firing. The weighted average is requested to be based on load (i.e., the sum of the hourly ppmvd corrected to 15% O_2 multiplied by the hourly load over the block 24-hour period divided by the total load over the block 24-hour period). The emission level proposed for gas firing is equivalent to 0.16 lb/MW which is over 9 times lower than the recently promulgated EPA new source performance standards (NSPS) for steam electric units. This new NSPS has a NOx limit for new sources of 1.6 lb/MW (September 16, 1998; 63FR179).

4.8 BACT ANALYSIS FOR SO_2 AND H_2SO_4 MIST

4.8.1 Potential Control Technologies

The NSPS established by EPA for emissions from CTs sets a maximum SO_2 level in the flue gas of 150 ppmvd or a maximum fuel sulfur content of 0.8 percent by weight (40 CFR 60, Subpart GG). Technologies employed to control SO_2 and H_2SO_4 mist emissions from combustion sources consist of fuel treatment and post-combustion add-on controls; i.e., flue gas desulfurization (FGD) systems.

4.8.1.1 Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to end fuel users. For wellhead natural gas containing sulfur compounds (e.g., hydrogen sulfide) and for crude oil, a variety of technologies are used by fuel suppliers to remove these sulfur compounds prior to delivery to customers.

4.8.1.2 Flue Gas Desulfurization

FGD systems remove SO_2 from exhaust streams by utilizing an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using either a wet- or dry-contact system. FGD wet scrubbers typically employ sodium, calcium, or dual-alkali reagents using packed or spray towers. Wet FGD systems will generate wastewater and wet sludge streams requiring treatment and disposal. In a dry FGD system, an alkaline slurry is injected into the combustion process exhaust stream. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment

4.8.1.3 Technical Feasibility

Current RBLC documents do not list any natural gas- or fuel oil-fired CC units that are required to use flue gas desulfurization (FGD) systems to meet SO_2 or H_2SO_4 emission requirements. The maximum emissions rates for Power Block 2 using pipeline natural gas and distillate fuel are equivalent to 0.003 and 0.06 lb/MMBtu, respectively. These levels are clearly within the ranges established as BACT for other projects.

The high pressure drops across FGD systems make them technically infeasible for application on CC units. Also, addition of an FGD system would be an inappropriate method of SO_2 or H_2SO_4 control, because emissions of these pollutants will be low. The significant capital and operating costs associated with FGD would make the project economically infeasible.

4.8.2 Proposed BACT Emission Limitations

Because post-combustion SO_2 and H_2SO_4 mist controls are not applicable, use of low sulfur fuel is considered to represent BACT for the Hines Energy Complex Power Block 2 CTs. Natural gas utilized at the Project will contain no more than 1.0 grain of sulfur per 100 scf and the distillate fuel oil will contain no more than 0.05 percent sulfur, by weight. Based on economic, energy, and environmental considerations, firing natural gas as the primary fuel and limiting the amount of time low sulfur fuel oil operation will be allowed (i.e., a total of 27,365,000 gallons per year, based on an aggregate of 2,000 hours per year of operation at full load) is proposed as BACT for SO_2 and H_2SO_4 emissions.

4.9 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Emission rates and methods of compliance proposed as BACT for each pollutant subject to review are summarized in Table 4-7.

Table 4-1. Summary of Best Available Control Technology (BACT) Determinations for CO Emissions for Combustion Turbines

Facility Name	State	Permit Number	Permit Issue Date	Unit/Process Description	Capacity (size)	CO Emission Limit	Control Method	Basis
KISSIMMEE UTILITIES AUTHORITY	FL	PSD FL 264	12/16/99	TURBINE, COMBUSTION	250.00 MW	12.0000 PPM	GOOD COMBUSTION	BACT-PSD
DUKE ENERGY NEW SMYRNA BEACH POWER CO. LP	FL	PSD FL 267	10/18/99	TURBINE GAS COMBINED CYCLE	500.00 MW (2 UNITS)	12.0000 PPM	GOOD COMBUSTION	BACT-PSD
OLEANDER POWER PROJECT	FL	PSD FL 258	10/1/99	TURBINE GAS COMBINED CYCLE	190.00 MW	12.0000 PPM @ 15% O2	GOOD COMBUSTION	BACT-PSD
PDC EL PASO MILFORD LLC	CT	105-0088	4/16/99	TURBINE, COMBUSTION, ABB GT 24, #1 WITH 2 CHILLERS	1.97 MMCF/H	13.0000 LB/H NAT GAS	OXIDATION CATALYST	BACT-PSD
PDC EL PASO MILFORD LLC	CT	105-0089	4/16/99	TURBINE, COMBUSTION, ABB GT 24, #2 WITH 2 CHILLERS	1.97 MMCF/H	13.0000 LB/H NAT GAS	OXIDATION CATALYST	BACT-PSD
ALABAMA POWER COMPANY - THEODORE COGENERATION	AL	503-8073	3/16/99	TURBINE, WITH DUCT BURNER	170.00 MW	0.0880 LB/MMBTU	EFFICIENT COMBUSTION	BACT-PSD
WYANDOTTE ENERGY	MI	275-98	2/8/99	TURBINE, COMBINED CYCLE, POWER PLANT	500.00 MW	3.0000 PPM	CATALYTIC OXIDATION	LAER
MOBILE ENERGY LLC	AL	503-0098	1/5/99	TURBINE, GAS, COMBINED CYCLE	168.00 MW	0.0400 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
TENASKA GEORGIA PARTNERS, L.P.	GA	4911-148-0004-P-01-0	12/18/98	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.00 MW EA	15.0000 PPMVD @ 15% O2	USING 15% EXCESS AIR, CO EMISSION IS BECAUSE OF NATURAL GAS	BACT-PSD
TENASKA GEORGIA PARTNERS, L.P.	GA	4911-148-0004-P-01-0	12/18/98	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.00 MW EA	33.0000 PPMVD	CO EMISSION IS BECAUSE OF FUEL OIL. WHEN OUTPUT IS BELOW 122 MW LIMIT IS 33 PPMVD AND ABOVE 122 MW LIMIT IS [illegible]	BACT-PSD
WESTBROOK POWER LLC	ME	A-743-71-A-N	12/4/98	TURBINE, COMBINED CYCLE, TWO	528.00 MW TOTAL	15.0000 PPM @ 15% O2	USING 15% EXCESS AIR	BACT-PSD
GORHAM ENERGY LIMITED PARTNERSHIP	ME	A-736	12/4/98	TURBINE, COMBINED CYCLE	900.00 MW TOTAL	6.0000 PPM @ 15% O2 WAT GA	BURN SULFUR DISTILLATE OIL #2 IS USED. EMISSION IS FROM EACH 300 MW SYSTEM	BACT-PSD
SANTA ROSA ENERGY LLC	FL	PSD FL 253	12/4/98	TURBINE, COMBUSTION, NATURAL GAS	241.00 MW	0.0000	DRY LOW NOX BURNER GOOD COMBUSTION PRACTICE	BACT-PSD
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	ME	A-22-71-N-A	8/14/98	TURBINE, COMBINED CYCLE, NATURAL GAS	175.00 MW	9.0000 PPMVD @ 15% O2 GAS		BACT-PSD
ALABAMA POWER PLANT BARRY	AL	503-1001	8/7/98	TURBINE, COMBUSTION, NATURAL GAS	510.00 MW TOTAL	0.0570 LB/MMBTU	EFFICIENT COMBUSTION	BACT-OTHER
TNP TECHN. LLC (FORMERLY TX-NM POWER CO.)	NM	PSD-NM-80-M-2	8/7/98	GAS TURBINES	375.00 MMBTU/H	10.0000 PPM	GOOD COMBUSTION PRACTICES	BACT-PSD
CASCO BAY ENERGY CO	ME	A-728	7/13/98	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170.00 MW EACH	20.0000 PPM @ 15% O2	15% EXCESS AIR	BACT-PSD
CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	FL	PSD FL 245	7/10/98	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALSO	2174.00 MMBTU/H	25.0000 PPM	GOOD COMBUSTION WITH DRY LOW NOX BURNERS OXIDATION CATALYST MAY BE USED	BACT-PSD
COLORADO SPRINGS UTILITIES-NIXON POWER PLANT	CO	96EP137	6/30/98	SIMPLE CYCLE TURBINE, NATURAL GAS	1327.00 MMBTU/HR	<9.00 DRS	CATALYTIC OXIDATION	BACT-PSD
BRIDGEPORT ENERGY, LLC	CT	0150180 & 0150181	6/29/98	TURBINES, COMBUSTION, MODEL V84.3A, 2 SIEMENS	260.00 MW/HRSG PER TURBINE	10.0000 PPM GAS & OIL	PRE MIX FUEL FAIL TO OPTIMIZE EFFICIENCY ACTUAL EMISSIONS EXPECTED BETWEEN 6 PPM	BACT-PSD
ENCOGEN HAWAII, L.P.	HI	0243-01-C	6/9/98	TURBINES, COMBUSTION, 3 EA	22.00 MW	67.5000 PPMVD @ 15% O2	GOOD COMBUSTION DESIGN AND OPERATION	BACT-PSD
CITY OF TALLAHASSEE UTILITY SERVICES	FL	PSD FL 239	5/26/98	TURBINE COMBINED CYCLE, MULTIPLE FUELS	1488.00 MMBTU/H	0.0000 SEE P2 DESCRIPTION	GOOD COMBUSTION OF CLEAN FUELS	BACT-PSD
GENERAL ELECTRIC PLASTICS	AL	707-0008-X016	4/27/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)	0.00	0.0500 LB/MMBTU	PROPER COMBUSTION	BACT-OTHER
RUMFORD POWER ASSOCIATES	ME	A-724-71-A-N	4/1/98	TURBINE GENERATOR, COMBUSTION, NATURAL GAS	1906.00 MMBTU/H	18.0000 PPM @ 15% O2	GE DRY LOW NOX COMBUSTOR DESIGN GOOD COMBUSTION CONTROL	BACT-PSD
ANDROSCOGGIN ENERGY LIMITED	ME	A-710-71-A-N	3/31/98	GAS TURBINES COGEN, W/DUCT BURNERS	475.00 MMBTU/H TURBINE	74.2100 LB/H NG	CATALYTIC OXIDATION, GOOD COMBUSTION PRACTICES	BACT-PSD
ANDROSCOGGIN ENERGY LIMITED	ME	A-710-71-A-N	3/31/98	GAS TURBINES COGEN, W/DUCT BURNERS	475.00 MMBTU/H TURBINE	48.7300 LB/H NG OIL	CATALYTIC OXIDATION, GOOD COMBUSTION PRACTICES	BACT-PSD
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/98	TURBINE STATIONARY	33.30 MW	25.0000 PPM @ 15% O2		OTHER
TIVERTON POWER ASSOCIATES	RI	RI-PSD-6	2/18/98	COMBUSTION TURBINE, NATURAL GAS	265.00 MW	12.0000 PPM @ 15% O2	GOOD COMBUSTION	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	LA	PSD-LA-622	2/13/98	TURBINE GAS GE, 7ME ?	598.00 MMBTU/H	25.0000 PPMV	GOOD EQUIPMENT DESIGN, PROPER COMBUSTION TECHNIQUE AND MIN. 2% EXCESS O2	BACT-PSD
MILLENNIUM POWER PARTNER LP	MA	130821	2/2/98	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2534.00 MMBTU/H	0.0700 LB/MMBTU	DRY LOW NOX COMBUSTION TECHNOLOGY IN CONJUNCTION WITH SCR ADD ON NOX CONTROL	BACT-PSD
MAUI ELECTRIC COMPANY	HI	0067-01-C	1/6/98	TURBINE, COMBUSTION, 2 EA	20.00 MW	44.0000 PPMVD @ 15% O2	GOOD COMBUSTION DESIGN AND OPERATION	BACT-PSD
BASF CORPORATION	LA	PSD-LA-613	12/30/97	DUCT BURNER COGEN UNIT NO. 2	0.40 MMLB/H STEAM	35.9500 LB/H	GOOD DESIGN, PROPER OPERATING PRACTICES 2% EXCESS O2	BACT-PSD
BASF CORPORATION	LA	PSD-LA-613	12/30/97	TURBINE, COGEN UNIT 2, GE FRAME 6	42.40 MW	33.5200 LB/MMBTU	GOOD DESIGN PROPER COMBUSTION TECHNIQUES 2% EXCESS O2	BACT-PSD
BUCKNELL UNIVERSITY	PA	60-0001A	11/26/97	NG FIRED TURBINE SOLAR TAURUS T-7300S	5.00 MW	50.0000 PPMV@15%O2	GOOD COMBUSTION	BACT-OTHER
DIGHTON POWER ASSOCIATE, LP	MA	4B96096	10/6/97	TURBINE, COMBUSTION, ABB GT11N2	1327.00 MMBTU/H	5.8700 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD ON NOX CONTROL	BACT-PSD
BERKSHIRE POWER DEVELOPMENT, INC.	MA	1-X-95-083	8/22/97	TURBINE, COMBUSTION, ABB GT24	1792.00 MMBTU/H	14.5000 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD ON NOX CONTROL	BACT-PSD
UNIVERSITY OF MEDICINE & DENTISTRY OF NEW JERSEY	NJ	[illegible]	6/26/97	COMBUSTION TURBINE COGENERATION UNITS 3	96.00 MMBTU/H	25.0000 PPMVD NAT. GAS		BACT
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE NATURAL GAS FIRED, ELEC. GEN.	100.00 MW	27.0000 LB/HR	DRY LOW NOX TECHNOLOGY BY MAINTAINING PROPER AIR FUEL RATIO	BACT-PSD
COLO. POWER PARTNERS BRUSH COGEN FAC	CO	91MR033	3/27/97	COGEN TURBINES W/DUCT BURNERS & BOILERS	365.00 MM BTU/H	34.0000 PPM @ 15% O2	GOOD COMBUSTION	BACT-PSD
MEAD COATED BOARD, INC.	AL	211-0004	3/12/97	COMBINED CYCLE TURBINE (25 MW)	568.00 MMBTU/H	28.0000 PPMVD@15% O2 (GAS)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	LA	PSD-LA-580 (M-2)	3/7/97	TURBINE/HRSG GAS COGENERATION	450.00 MM BTU/H	70.0000 LB/H	COMBUSTION DESIGN AND CONSTRUCTION	BACT-PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-622-M-2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100.00 MW	0.0000 SEE FACILITY NOTES	GOOD COMBUSTION PRACTICES	BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES COMBINED-CYCLE COGENERATION	461.00 MW	100.0000 PPMDV AT MIN LOAD	COMBUSTION CONTROLS	BACT-PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED-CYCLE COGENERATION	461.00 MW	33.0000 PPMDV	COMBUSTION CONTROLS	BACT-PSD
BLUE MOUNTAIN POWER, LP	PA	06-328-009	7/31/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	152.00 MW	3.0000 PPM @ 15% O2	OXIDATION CATALYST 10 PPM @ 15% O2 WHEN FIRING NO. 2 OIL AT 75% NO LIMIT SET TO 27.1 PPM	OTHER
COMMONWEALTH CHESAPEAKE CORPORATION	VA	40866	6/21/96	3 COMBUSTION TURBINES (OIL FIRED)	6000.00 HRS/YR	90.0000 TPY	GOOD COMBUSTION OPERATING PRACTICES	BACT-PSD
PORTSIDE ENERGY CORP	IN	CP 127 5260	6/13/96	TURBINE NATURAL GAS FIRED	63.00 MEGAWATT	40.0000 LB/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 60 PPMVD AT 15% OXYGEN	BACT-PSD
PORTSIDE ENERGY CORP.	IN	CP 127 5260	6/13/96	TURBINE, NATURAL GAS FIRED	63.00 MEGAWATT	17.0000 LB/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED 50 PPMVD AT 15% OXYGEN	BACT-PSD
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	CO	94WE508	5/1/96	COMBINED CYCLE TURBINES (2) NATURAL	471.00 MW	15.0000 PPMVD, SMPL CY	GOOD COMBUSTION CONTROL PRACTICES COMMITMENT TO A PATTERN OF OPERATION (LOAD VARIATIONS ETC) TO MIN	BACT-PSD
GENERAL ELECTRIC GAS TURBINES	SC	1200-0084	4/19/96	I.C. TURBINE	2700.00 MMBTU/HR	######## LB/HR	GOOD COMBUSTION PRACTICES TO MINIMIZE EMISSIONS	BACT-PSD
CAROLINA POWER & LIGHT	NC	1812	4/11/96	COMBUSTION TURBINE, 4 EACH	1807.40 MMBTU/HR	81.0000 LB/HR	COMBUSTION CONTROL	BACT-PSD
CAROLINA POWER & LIGHT	NC	1812	4/11/96	COMBUSTION TURBINE, 4 EACH	1807.40 MMBTU/HR	80.0000 LB/HR	COMBUSTION CONTROL	BACT-PSD
SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MS	1360-00036	4/9/96	COMBUSTION TURBINE, COMBINED CYCLE	1299.00 MMBTU/HR NAT GAS	25.0000 PPM @ 15% O2, GAS	GOOD COMBUSTION CONTROLS	BACT-PSD
MID-GEORGIA COGEN	GA	4911-076-11763	4/3/96	COMBUSTION TURBINE (2) NATURAL GAS	116.00 MW	10.0000 PPMVD	COMPLETE COMBUSTION	BACT-PSD
MID-GEORGIA COGEN.	GA	4911-076-11763	4/3/96	COMBUSTION TURBINE (2), FUEL OIL	116.00 MW	30.0000 PPMVD	COMPLETE COMBUSTION	BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD LA 567	3/26/96	GENERATOR, NATURAL GAS FIRED TURBINE	1123.00 MM BTU/HR	872.4000 TPY CAP FOR 3 TURB	GOOD COMBUSTION PRACTICE AND PROPER OPERATION	BACT-PSD
SEMINOLE HARDEE UNIT 3	FL	PA 89-256A / PSD FL 214	1/1/96	COMBINED CYCLE COMBUSTION TURBINE	140.00 MW	20.0000 PPM (NAT. GAS)	DRY LNB GOOD COMBUSTION PRACTICES	BACT-PSD
MINNESOTA METHANE	AZ	95-0241	11/12/95	ENGINES, COGENERATION (4)	800.00 KW	99.8000 TPY	AIR/FUEL CONTROLLER	BACT-PSD
KEY WEST CITY ELECTRIC SYSTEM	FL	AC44-246398 / PSD FL 210	9/28/95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23.00 MW	20.0000 PPM @ 15% O2 FULL LO	GOOD COMBUSTION	BACT
UNION CARBIDE CORPORATION	LA	PSD LA 590	8/22/95	DUCT BURNER	210.00 MM BTU/HR	130.8000 LB/HR COMMON VENT	NO ADD ON CONTROL GOOD COMBUSTION PRACTICE	BACT-PSD
UNION CARBIDE CORPORATION	LA	PSD LA 590	8/22/95	GENERATOR, GAS TURBINE	1313.00 MM BTU/HR	130.8000 LB/HR	NO ADD ON CONTROL GOOD COMBUSTION PRACTICE	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	PR	PR-0100	7/31/95	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248.00 MW	104.0000 LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES	BACT-PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	PR	PR-0100	7/31/95	COMBUSTION TURBINES (3) 83 MW SIMPLE-CYCLE EACH	248.00 MW	104.0000 LB/HR	MAINTAIN EACH TURBINE IN GOOD WORKING ORDER AND IMPLEMENT GOOD COMBUSTION PRACTICES	BACT-PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS LP	NY	2-6101-00185/00002-0	6/6/95	TURBINE, OIL FIRED	240.00 MW	5.0000 PPM @ 15% O2		LAER
BROOKLYN NAVY YARD COGENERATION PARTNERS LP	NY	2-6101-00185/00002-0	6/6/95	GENERATOR, 3000 KW EMERGENCY	3000.00 KW	0.2500 LB/MMBTU		LAER
BROOKLYN NAVY YARD COGENERATION PARTNERS LP	NY	2-6101-00185/00002-0	6/6/95	TURBINE, NATURAL GAS FIRED	240.00 MW	4.0000 PPM @ 15% O2		LAER
PANDA-KATHLEEN, L.P.	FL	AC53-261088/PSD FL 218	6/1/95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75.00 MW	25.0000 PPM @ 15% O2	COMBUSTION CONTROLS STANDARD ONLY APPLIES IF GE CT IS SELECTED THE ABB CT WAS LESS THAN	BACT-PSD
ALGONQUIN GAS TRANSMISSION COMPANY	MA	LOG# 94-0070	3/31/95	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.10 MW EACH	16.2000 LB/H		BACT
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	PSD LA 580 (M-1)	3/2/95	TURBINE/HRSG GAS COGENERATION	450.00 MM BTU/HR	25.2000 LB/H	PROPER OPERATION	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	0395-016	3/28/95	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	56.77 MW	477.8000 TPY	GOOD COMBUSTION CONTROL	BACT-PSD
MARATHON OIL CO. - INDIAN BASIN N G PLAN	NM	PSD-NM-390-M-2	1/11/95	TURBINES, NATURAL GAS (2)	5600.00 HP	13.2000 LBS/H	LEAN-PREMIXED COMBUSTION TECHNOLOGY	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	NY	313201 2010/00001-00007	12/10/94	SIEMENS V84.3 GAS TURBINE (EP #00001)	850.00 MMBTU/H	9.5000 PPM	NO CONTROLS	BACT-OTHER
INDECK-OSWEGO ENERGY CENTER	NY	351200 0011 00001	10/6/94	DUCT BURNER	30.00 MMBTU/HR	0.1290 LB/MMBTU 3.94 LB/HR	NO CONTROLS	BACT-OTHER
INDECK-OSWEGO ENERGY CENTER	NY	351200 0011 00001	10/6/94	GE FRAME 6 GAS TURBINE	553.00 LB/MMBTU	10.0000 PPM 10.00 LB/HR	NO CONTROLS	BACT-OTHER
FULTON COGEN PLANT	NY	350400 0021 00001	9/16/94	GE LM5000 GAS TURBINE	500.00 MMBTU/HR	107.0000 PPM 120 LB/HR	NO CONTROLS	BACT-OTHER
CAROLINA POWER AND LIGHT	SC	0820-0033	8/31/94	STATIONARY GAS TURBINE	1620.00 MMBTU/H	414.0000 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	BACT-PSD
CAROLINA POWER AND LIGHT	SC	0820-0033	8/31/94	STATIONARY GAS TURBINE	1620.00 MMBTU/H	302.0000 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	BACT-PSD
BEAR MOUNTAIN LIMITED	CA	S 2048 1 2	6/10/94	TURBINE, GE, COGENERATION 40 MW	48.00 MW	252.0000 LB/D	OXIDATION CATALYST	BACT-OTHER
HERMISTON GENERATING CO.	OR	30-0113	7/7/94	TURBINES, NATURAL GAS (2)	1696.00 MMBTU/H	15.0000 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
MUDDY RIVER L.P.	NV	A0113	6/10/94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140.00 MEGAWATT	77.0000 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
CBW NEVADA, INC.	NV	A0110	6/10/94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140.00 MEGAWATT	83.0000 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
PORTLAND GENERAL ELECTRIC CO.	OR	26-0001	5/31/94	TURBINES, NATURAL GAS (2)	1720.00 MMBTU	15.0000 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	0684-036	5/17/94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1346.00 MMBTU/HR	120.0000 TPY	NONE	BACT-PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	0684-036	5/17/94	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1346.00 MMBTU/HR	1280.0000 TPY	NONE	BACT-PSD
WEST CAMPUS COGENERATION COMPANY	TX	23002/PSD TX 817	5/2/94	GAS TURBINES	76.20 MW (TOTAL POWER)	300.0000 TPY	INTERNAL COMBUSTION CONTROLS	BACT
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD FL-195	2/25/94	TURBINE, NATURAL GAS (2)	1510.00 MMBTU/H	25.0000 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD FL-195	2/25/94	TURBINE, FUEL OIL (2)	1730.00 MMBTU/H	30.0000 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
INTERNATIONAL PAPER	LA	PSD-LA-[illegible] (M-3)	2/24/94	TURBINE/HRSG, GAS COGEN	338.00 MM BTU/HR TURBINE	146.8000 LB/HR	COMBUSTION CONTROL	BACT
TECO POLK POWER STATION	FL	PSD FL-194	2/24/94	TURBINE, SYNGAS (COAL GASIFICATION)	1755.00 MMBTU/H	25.0000 PPMVD	GOOD COMBUSTION	BACT-PSD
TECO POLK POWER STATION	FL	PSD FL-194	2/24/94	TURBINE, FUEL OIL	1755.00 MMBTU/H	40.0000 PPMVD	GOOD COMBUSTION	BACT-PSD
KAMINE/BESICORP CARTHAGE L.P.	NY	226001 0005 00001	1/18/94	GE FRAME 6 GAS TURBINE	481.00 BTU/HR	10.0000 PPM, 11.0 LB/HR	NO CONTROLS	BACT-OTHER
ORANGE COGENERATION LP	FL	PSD FL-208	12/30/93	TURBINE, NATURAL GAS 2	368.90 MMBTU/H	30.0000 PPMVD	GOOD COMBUSTION	BACT-PSD
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715.00 MMBTU/HR	108.4000 LB/HR TEMP > 20F	OXIDATION CATALYST	BACT
PROJECT ORANGE ASSOCIATES	NY	311500 2015 00001	12/1/93	GE LM 6000 GAS TURBINE	550.00 MMBTU/HR	87.0000 LB/HR TEMP > 20F	NO CONTROLS	BACT-OTHER
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	PSD-NM-340-M2	10/20/93	TURBINE, GAS FIRED	11267.00 HP	60.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
CROCKETT COGENERATION - C&H SUGAR	CA	S 291	10/5/93	TURBINE GAS GENERAL ELECTRIC MODEL PG7221(FA)	240.00 MW	6.0000 PPMVD @ 15% O2	ENGELHARD OXIDATION CATALYST	BACT-OTHER
PATOWMACK POWER PARTNERS LIMITED PARTNERSHIP	VA	71876	9/16/93	TURBINE, COMBUSTION, SIEMENS MODEL V84.2 2	10.20 X10(9) SCF/YR NAT GAS	29.0000 LB/HR	GOOD COMBUSTION OPERATING PRACTICES	BACT-PSD
FLORIDA GAS TRANSMISSION COMPANY	AL	503 3026 X005	8/9/93	TURBINE NATURAL GAS	12600.00 BHP	0.4200 G/BHP HR	AIR TO FUEL RATIO CONTROL DRY COMBUSTION CONTROLS	BACT-PSD
LOCKPORT COGEN FACILITY	NY	292600 0448/00001-00007	7/14/93	(3) DUCT BURNER (EP #1 00001-00003)	84.10 MMBTU/HR	0.1000 LB/MMBTU 8.4 LB/HR	NO CONTROLS	BACT-OTHER
LOCKPORT COGEN FACILITY	NY	292600 0448/00001-00007	7/14/93	(3) GE FRAME 6 TURBINES (EP #1 00001-00006)	423.80 MMBTU/HR	10.0000 PPM	NO CONTROLS	BACT-OTHER
AMTEC COGEN PLANT	NY	080200 0461	7/7/93	DUCT BURNER EP #00001	70.00 MMBTU/HR	0.0350 LB/MMBTU, 2.5 LB/HR	NO CONTROLS	BACT-OTHER
AMTEC COGEN PLANT	NY	080200 0461	7/7/93	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451.00 MMBTU/HR	36.0000 PPM, 33 LB/HR	BAFFLE CHAMBER	SEE NOTE #4
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01 92 6231 TO 01 92 6261	6/9/93	TURBINES COMBUSTION, NATURAL GAS-FIRED (2)	617.00 MMBTU/HR (EACH)	1.8000 PPMDV	OXIDATION CATALYST	OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01 92 6231 TO 01 92 6261	6/9/93	TURBINES, COMBUSTION, KEROSENE FIRED (2)	840.00 MMBTU/H (EACH)	2.8000 PPMDV	OXIDATION CATALYST	OTHER
PSI ENERGY, INC. WABASH RIVER STATION	IN	CP 167 2010	6/22/93	COMBINED CYCLE SYNGAS TURBINE	1776.00 MMBTU/HR	15.0000 LESS THAN PPM	OPERATION PRACTICES AND GOOD COMBUSTION COMBINED CYCLE SYNGAS TURBINE	BACT-PSD
TIGER BAY LP	FL	PSD FL-190	6/17/93	DUCT BURNER, GAS	100.00 MMBTU/H	10.0000 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
TIGER BAY LP	FL	PSD FL-190	6/17/93	TURBINE, GAS	1814.00 MMBTU/H	49.0000 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
TIGER BAY LP	FL	PSD FL-190	6/17/93	TURBINE, OIL	1848.00 MMBTU/H	68.4000 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK ENERGY COMPANY	NY	663200 0090	6/12/93	DUCT BURNER EP #00001	100.00 MMBTU/HR	0.1400 LB/MMBTU, 12.0 LB/HR	NO CONTROLS	BACT-OTHER
INDECK ENERGY COMPANY	NY	663200 0090	6/12/93	GE FRAME 6 GAS TURBINE EP #00001	481.00 MMBTU/HR	40.0000 PPM	NO CONTROLS	BACT-OTHER
PHOENIX POWER PARTNERS	CO	87WE125J	6/11/93	GENERATOR, STEAM, W/ DUCT BURNER	50.00 MMBTU/HR	81.1800 TPY	FUEL SPEC: NATURAL GAS COMBUSTION	OTHER
LILCO SHOREHAM	NY	472200 6378	6/10/93	(2) GE FRAME 7 TURBINES (EP #1 00001 & [illegible])	850.00 MMBTU/HR	10.0000 PPM, 18.7 LB/HR	NO CONTROLS	BACT-OTHER
TRIGEN MITCHEL FIELD	NY	282089 4163 00006	4/16/93	GE FRAME 6 GAS TURBINE	424.70 MMBTU/HR	10.0000 PPM, 10.0 LB/HR	NO CONTROLS	BACT-OTHER
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD 182	4/7/93	TURBINE, NATURAL GAS	868.00 MMBTU/H	54.0000 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	387.00 MMBTU/H	40.0000 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD 182	4/7/93	TURBINE, FUEL OIL	928.00 MMBTU/H	65.0000 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD 182	4/7/93	TURBINE, FUEL OIL	371.00 MMBTU/H	78.0000 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
EAST KENTUCKY POWER COOPERATIVE	KY	C-93-046	3/24/93	TURBINES (3) #2 FUEL OIL AND NAT. GAS FIRED	1492.00 MMBTU/H (EACH)	76.0000 LB/H (EACH)	PROPER COMBUSTION TECHNIQUES	BACT-OTHER
INTERNATIONAL PAPER CO. RIVERDALE MILL	AL	104-0003-X028	1/11/93	TURBINE, STATIONARY (GAS FIRED) WITH DUCT BURNER	40.00 MW	27.1000 LB/HR	DESIGN	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD FL-186	12/14/92	TURBINE GAS	1214.00 MMBTU/H	15.0000 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
AUBURNDALE POWER PARTNERS, LP	FL	PSD FL-186	12/14/92	TURBINE, OIL	1170.00 MMBTU/H	25.0000 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	7-3556-00040/00007-0	11/24/92	TURBINES COMBUSTION (4) (NATURAL GAS) (1012 MW)	2133.00 MMBTU/HR (EACH)	13.0000 PPM	COMBUSTION CONTROLS	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	6-2320-00015/00001-0	11/6/92	TURBINE COMBUSTION (NAT. GAS & OIL FUEL) (76MW)	650.00 MMBTU/HR	8.6000 PPM	COMBUSTION CONTROLS	BACT-OTHER
GRAYS FERRY CO. GENERATION PARTNERSHIP	PA	02101 TO 02104	11/4/92	TURBINE NATURAL GAS & OIL	1160.00 MMBTU	0.0058 LB/MMBTU (GAS)*	COMBUSTION	BACT-OTHER
GRAYS FERRY CO. GENERATION PARTNERSHIP	PA	02101 TO 02104	11/4/92	GENERATOR STEAM	480.00 MMBTU	0.0056 LB/MMBTU (NAT GAS)*	COMBUSTION	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	VA	50840	10/30/92	TURBINE, COMBUSTION GAS	474.00 X10(6) BTU/HR N. GAS	11.0000 LB/HR	GOOD COMBUSTION	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	50840	10/30/92	TURBINE, COMBUSTION GAS	466.00 X10(6) BTU/HR #2 OIL	11.0000 LB/HR	GOOD COMBUSTION	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	50840	10/30/92	TURBINE, COMBUSTION GAS (TOTAL)	0.00	48.2000 TPY	GOOD COMBUSTION	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	REGISTRATION # 40806	6/25/92	TURBINE FACILITY, GAS	1311.13 X10(6) SCF/Y NAT GAS	249.8000 TOTAL TPY	GOOD COMBUSTION PRACTICES	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	REGISTRATION # 40806	6/25/92	TURBINE FACILITY GAS	7.44 X10(3) GPY FUEL OIL	249.8000 TOTAL TPY	GOOD COMBUSTION PRACTICES	BACT-PSD

Table 4-1. Summary of Best Available Control Technology (BACT) Determinations for CO Emissions for Combustion Turbines

Facility Name	State	Permit Number	Permit Issue Date	Unit/Process Description	Capacity/Level	CO Emission Limit	Control Method	Basis
GORDONSVILLE ENERGY L.P.	VA	REGISTRATION #40808	6/26/92	TURBINES (2) (EACH WITH A DB)	1.51 X10(9) BTU/HR N GAS	67.0000 LB/HR/UNIT	GOOD COMBUSTION PRACTICES	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	REGISTRATION #40808	6/26/92	TURBINES (2) (EACH WITH A DB)	1.30 X10(9) BTU/H #2 OIL	66.0000 LB/HR/UNIT	GOOD COMBUSTION PRACTICES	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A533	6/18/92	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600.00 MW (8 UNITS 75 EACH)	162.6000 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	NY	414401 0212 00001	6/10/92	GE FRAME 9 GAS TURBINE	481.00 MMBTU/HR	8.0000 PPM, 11.0 LB/HR	NO CONTROLS	BACT-OTHER
NORTHERN STATES POWER COMPANY	SD	NONE	6/2/92	TURBINE, SIMPLE CYCLE, 4 EACH	138.00 MW	60.0000 PPM FOR GAS	GOOD COMBUSTION TECHNIQUES	BACT-PSD
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00826/00001-0	6/1/92	GENERATOR, EMERGENCY (NATURAL GAS)	1.60 MMBTU/HR	8.5000 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
PASNY/HOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00826/00001-0	6/1/92	TURBINE, COMBUSTION GAS (150 MW)	1148.00 MMBTU/HR (GAS)	4.5000 PPM	COMBUSTION CONTROL	BACT-OTHER
WEPCO, PARIS SITE	WI	91 RV 043	5/28/92	TURBINES, COMBUSTION (4)	0.00	25.0000 LB/HR (SEE NOTES)		BACT-PSD
FLORIDA POWER CORPORATION	FL	FL-PSD 180	6/17/92	TURBINE, OIL	1020.00 MMBTU/H	64.0000 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FLORIDA POWER CORPORATION	FL	FL-PSD 180	6/17/92	TURBINE, OIL	1860.00 MMBTU/H	70.0000 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
CNG TRANSMISSION	OH	01-3870	6/12/92	TURBINE (NATURAL GAS) (3)	5600.00 HP (EACH)	0.0150 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS	OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00108/00001-0	7/31/92	BURNERS, DUCT (2)	660.00 MMBTU/HR EACH	0.0600 LB/MMBTU	OXIDATION CATALYST	BACT-OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00108/00001-0	7/31/92	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123.00 MMBTU/HR (EACH)	3.0000 PPM	OXIDATION CATALYST	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10841	7/28/92	TURBINE, GAS FIRED (2 EACH)	1817.00 MMBTU/H	25.0000 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10841	7/28/92	TURBINE, OIL FIRED (2 EACH)	1840.00 MMBTU/H	25.0000 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	HI	HI 90-05	7/20/92	TURBINE, COMBINED CYCLE COMBUSTION	28.00 MW	28.8000 LB/HR	COMBUSTION TECHNOLOGY/DESIGN	BACT-OTHER
INDECK-YERKES ENERGY SERVICES	NY	146400 0133	6/24/92	DUCT BURNER (EP #00001)	20.00 MMBTU/HR	0.0400 LB/MMBTU, 0.8 LB/HR	NO CONTROLS	BACT-OTHER
INDECK-YERKES ENERGY SERVICES	NY	146400 0133	6/24/92	GE FRAME 6 GAS TURBINE (EP #00001)	432.20 MMBTU/HR	10.0000 PPM, 10 LB/HR	NO CONTROLS	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-0	6/18/92	DUCT BURNERS (2)	206.00 MMBTU/HR EACH	0.0730 LB/MMBTU GAS, 100%	COMBUSTION CONTROLS	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-0	6/18/92	DUCT BURNER	173.00 MMBTU/HR	0.0720 LB/MMBTU GAS (100%)	COMBUSTION CONTROL	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-0	6/18/92	COMBUSTION TURBINES (2) (252 MW)	1173.00 MMBTU/HR EACH	10.0000 PPM	COMBUSTION CONTROLS	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-0	6/18/92	COMBUSTION TURBINE (78 MW)	1173.00 MMBTU/HR	25.0000 PPM	COMBUSTION CONTROL	BACT-OTHER
TENASKA WASHINGTON PARTNERS, L.P.	WA	91-06	6/29/92	COGENERATION PLANT COMBINED CYCLE	1.83 MMBTU/HR	20.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
NORTHWEST PIPELINE CORPORATION	CO	91LP702(1) 21 MOD. #1	6/29/92	BURNERS, DUCT, COGEN	20.00 MMBTU/HR PER BURNER	4.0000 LB/HR		OTHER
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI PSD-4	4/13/92	TURBINE, GAS AND DUCT BURNER	1360.00 MMBTU/H EACH	11.0000 PPM @ 15% O2, GAS		BACT-PSD
KENTUCKY UTILITIES COMPANY	KY	C 92 008	3/10/92	TURBINE, #2 FUEL OIL/NATURAL GAS (6)	1600.00 MM BTU/HR (EACH)	76.0000 LB/HR (EACH)	COMBUSTION CONTROL	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	3/3/92	TURBINE, COMBUSTION	1176.00 MMBTU/H NAT. GAS	87.0000 LB/H/UNIT	FURNACE DESIGN	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	3/3/92	TURBINE, COMBUSTION	1117.00 MMBTU/H NO2 FUEL OIL	87.0000 LB/H/UNIT	FURNACE DESIGN	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	3/3/92	TURBINE, COMBUSTION, 2	0.00	220.2000 T/Y/UNIT		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	91WE007(1-6)	2/18/92	TURBINE, GAS FIRED 6 EACH	246.00 MMBTU/H	25.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-0628	2/12/92	TURBINES, 8	1002.00 MMBTU/H, NAT GAS	9.0000 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-0628	2/12/92	TURBINES, 8	872.00 MMBTU/H, #2 OIL	9.0000 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
HAWAIIAN ELECTRIC LIGHT CO., INC.	HI	HI 90-04	3/12/92	TURBINE, FUEL OIL #2	20.00 MW	20.0000 LB/HR @ 100% PEAKLD	COMBUSTION DESIGN	BACT-PSD
HAWAIIAN ELECTRIC LIGHT CO., INC.	HI	HI 90-04	3/12/92	TURBINE, FUEL OIL #2	20.00 MW	66.4000 LB/H @ 75-<100% PKLD	COMBUSTION DESIGN	BACT-PSD
HAWAIIAN ELECTRIC LIGHT CO., INC.	HI	HI 90-04	3/12/92	TURBINE, FUEL OIL #2	20.00 MW	181.0000 LB/H @ 50-<75% PKLD	COMBUSTION DESIGN	BACT-PSD
HAWAIIAN ELECTRIC LIGHT CO., INC.	HI	HI 90-04	3/12/92	TURBINE, FUEL OIL #2	20.00 MW	470.0000 LB/H @ 25-<50% PKLD	COMBUSTION DESIGN	BACT-PSD
KAMINE/BESICORP NATURAL DAM LP	NY	404088 0005 00001	12/31/91	GE FRAME 6 GAS TURBINE	600.00 MMBTU/HR	0.0200 LB/MMBTU, 10 LB/HR	NO CONTROLS	BACT-OTHER
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1313.00 MM BTU/HR	50.0000 LB/HR	COMBUSTION CONTROL	BACT-PSD
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/91	TURBINE, COMBUSTION	1247.00 MM BTU/HR	60.0000 LB/HR	COMBUSTION CONTROL	BACT-PSD
MAUI ELECTRIC COMPANY, LTD.	HI	HI 90-02	12/3/91	TURBINE, FUEL OIL #2	28.00 MW	0.0000 SEE NOTES	GOOD COMBUSTION PRACTICES	BACT-PSD
KALAMAZOO POWER LIMITED	MI	1234-90	12/3/91	TURBINE, GAS FIRED, 2 W/ WASTE HEAT BOILERS	1605.00 MMBTU/H	70.0000 PPMV	DRY LOW NOX TURBINES	BACT-PSD
LAKE COGEN LIMITED	FL	PSD FL 176	11/20/91	DUCT BURNER, GAS	160.00 MMBTU/H	0.2000 LB/MMBTU	NOT REQUIRED	BACT-PSD
LAKE COGEN LIMITED	FL	PSD FL 176	11/20/91	TURBINE, GAS, 2 EACH	42.00 MW	42.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
LAKE COGEN LIMITED	FL	PSD FL 176	11/20/91	TURBINE, OIL, 2 EACH	42.00 MW	76.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	PSD FL 173	11/6/91	TURBINE, GAS, 4 EACH	35.00 MW	10.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	PSD FL 173	11/6/91	TURBINE, OIL, 4 EACH	35.00 MW	10.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2048008-011	10/29/91	TURBINE, GAS FIRED	47.84 MMBTU/H	7.7400 PPM @ 15% O2	HIGH TEMPERATURE OXIDATION CATALYST	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2048008-011	10/29/91	TURBINE, GAS FIRED, SOLAR MODEL H	5400.00 HP	7.7400 PPM @ 15% O2	HIGH TEMP OXIDATION CATALYST	BACT-PSD
EL PASO NATURAL GAS	AZ		10/29/91	TURBINE, GAS, SOLAR CENTAUR H	5600.00 HP	10.5000 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	BACT-PSD
EL PASO NATURAL GAS	AZ		10/29/91	TURBINE, GAS, SOLAR CENTAUR H	5600.00 HP	10.5000 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	BACT-PSD
FLORIDA POWER GENERATION	FL	PSD FL 187	10/18/91	TURBINE, OIL, 4 EACH	82.00 MW	64.0000 LB/H	COMBUSTION CONTROL	BACT-PSD
EL PASO NATURAL GAS	AZ		10/18/91	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000.00 HP	60.0000 PPM @ 15% O2	LEAN BURN	BACT-PSD
SEK POWER SYSTEMS, ENCOGEN NW COGENERATION PROJECT	WA	91-02	8/28/91	TURBINES, COMBINED CYCLE COGEN GE FRAME 6	121.00 MW	10.0000 PPMDV @ 15% O2		BACT-PSD
CAROLINA POWER AND LIGHT CO.	SC	0820-0083-CA TO CC	8/23/91	TURBINE, I.C.	80.00 MW	80.0000 LB/H		BACT-PSD
ENRON LOUISIANA ENERGY COMPANY	LA	PSD LA 600	8/6/91	TURBINE, GAS, 2	39.10 MMBTU/H	80.0000 PPM @ 15% O2	BASE CASE, NO ADDITIONAL CONTROLS	BACT-PSD
ALGONQUIN GAS TRANSMISSION CO.	RI	1120-1127	7/31/91	TURBINE, GAS, 2	40.00 MMBTU/H	0.1140 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-OTHER
CHARLES LARSEN POWER PLANT	FL	PSD FL 108	7/25/91	TURBINE, GAS, 1 EACH	80.00 MW	25.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD FL 108	7/25/91	TURBINE, OIL, 1 EACH	80.00 MW	25.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
SUMAS ENERGY INC.	WA		6/26/91	TURBINE, NATURAL GAS	88.00 MW	6.0000 PPM @ 15% O2	CO CATALYST	BACT-PSD
SAGUARO POWER COMPANY	NV	A391	6/17/91	COMBUSTION TURBINE GENERATOR	34.60 MW	6.0000 PPH	CONVERTER (CATALYTIC)	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD FL 148	6/5/91	TURBINE, GAS, 4 EACH	400.00 MW	30.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD FL 148	6/5/91	TURBINE, CO, 4 EACH	400.00 MW	33.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-148	6/5/91	TURBINE, OIL, 2 EACH	400.00 MW	33.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
NORTHERN CONSOLIDATED POWER	PA	28-328-001	5/3/91	TURBINES, GAS 2	34.40 MW EACH	110.0000 T/YR	OXIDATION CATALYST	OTHER
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL: SEE NOTES	4/1/91	TURBINES (NATURAL GAS) (2)	1190.00 MMBTU/HR (EACH)	0.0260 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL: SEE NOTES	4/1/91	TURBINES (#2 FUEL OIL) (2)	1190.00 MMBTU/HR (EACH)	0.0800 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
CIMARRON CHEMICAL	CO	90WE436	3/26/91	TURBINE #7, GE FRAME 6	33.00 MW	250.0000 T/YR, LESS THAN	CO CATALYST	OTHER
FLORIDA POWER AND LIGHT	FL	PSD FL-146	3/14/91	TURBINE, GAS, 4 EACH	240.00 MW	30.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD FL 146	3/14/91	TURBINE, OIL, 4 EACH	0.00	33.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	A381	1/17/91	COMBINED CYCLE POWER GENERATION	85.00 MW POWER OUTPUT	30.8800 LB/HR	CATALYTIC CONVERTER	BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A380	1/17/91	COMBINED-CYCLE POWER GENERATION	85.00 MW TOTAL OUTPUT	30.8800 LB/HR	CATALYTIC CONVERTER	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NJ		11/1/90	TURBINE, KEROSENE FIRED	586.00 MMBTU/HR	0.0830 LB/MMBTU	CATALYTIC OXIDATION	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NJ		11/1/90	TURBINE, NATURAL GAS FIRED	586.00 MMBTU/HR	0.0056 LB/MMBTU	CATALYTIC OXIDATION	BACT-PSD
TBG COGEN COGENERATION PLANT	NY	282400 5708 00001	8/6/90	GE LM2500 GAS TURBINE	214.80 MMBTU/HR	0.1610 LB/MMBTU	CATALYTIC OXIDIZER	BACT
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0029	12/11/89	INTERNAL COMBUSTION TURBINE	110.00 MEGAWATTS	33.0000 LB/HR	GOOD COMBUSTION PRACTICES	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	MA	MBR 89 COM-002	11/30/89	TURBINE, 38 MW NATURAL GAS FIRED	417.00 MMBTU/HR	40.0000 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-OTHER
MEGAN RACINE ASSOCIATES INC	NY	402201 0205 00001	6/5/89	GE LM6000-N COMBINED CYCLE GAS TURBINE	401.00 LB/MMBTU	0.0290 LB/MMBTU, 11 LB/HR	NO CONTROLS	BACT-OTHER
UNOCAL	CA	A/N 180294 AND 180295	7/18/89	TURBINE GAS (SEE NOTES)	0.00	10.0000 PPM @ 15% O2	OXIDATION CATALYST	BACT-OTHER
KERN FRONT LIMITED	CA	S 1120-1-7	11/4/88	TURBINE, GAS, GENERAL ELECTRIC LM 2500	26.00 MW	946.1800 LBD	OXIDATION CATALYST	BACT-OTHER
TOYOTA MOTOR MANUFACTURING U.S.A. INC.	KY	C-88-117	9/17/86	COMBUSTION, NATURAL GAS	0.00	0.0331 LB/MMBTU		BACT-PSD
UNION ELECTRIC CO	MO	0579-014 TO 0579-016	6/6/79	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION TURBIN	622.00 MMBTU/HR	483.0000 TPY		BACT-PSD
MILAGRO, WILLIAMS FIELD SERVICE	NM	PSD NM 658 M-4		TURBINE/COGEN, NATURAL GAS (2)	900.00 MMCF/DAY	27.6000 PPM @ 15% O2		BACT-PSD
PILGRIM ENERGY CENTER	NY	472600 2084		(2) DUCT BURNER (EP #0 0001&2)	214.10 MMBTU/HR	0.1000 LB/MMBTU, 17.5 LB/HR		BACT-OTHER
PILGRIM ENERGY CENTER	NY	472600 2084		(2) WESTINGHOUSE W501DS TURBINES (EP #0 0001&2)	1400.00 MMBTU/HR	10.0000 PPM, 20.0 LB/HR		BACT-OTHER
LEDERLE LABORATORIES	NY	392400 0006		(2) GAS TURBINES (EP #0 00101&102)	110.00 MMBTU/HR	40.0000 PPM, 12.0 LB/HR		BACT-OTHER
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140.00 MW	20.0000 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
COLORADO POWER PARTNERSHIP	CO	91MN933,1 2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385.00 MMBTU/H EACH TURBINE	22.4000 PPM @ 15% O2		BACT-PSD

ALABAMA POWER COMPANY - THEODORE COGENERATION	AL	503 8073	3/16/99	TURBINE, WITH DUCT BURNER	170.00 MW	0.0540 LB/MMBTU	EFFICIENT COMBUSTION	BACT-PSD
GENERAL ELECTRIC PLASTICS	AL	207 0008 K010	6/27/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)	0.00	0.0800 LB/MMBTU	PROPER COMBUSTION	BACT-PSD
ANDROSCOGGIN ENERGY LIMITED	ME	A-718-71-A-N	3/31/98	GAS TURBINES COGEN. W/DUCT BURNERS	675.00 MMBTU/H TURBINE	74.2100 LB/H NG	CATALYTIC OXIDATION, GOOD COMBUSTION PRACTICES.	BACT-PSD
ANDROSCOGGIN ENERGY LIMITED	ME	A-718-71-A-N	3/31/98	GAS TURBINES COGEN. W/DUCT BURNERS	675.00 MMBTU/H TURBINE	43.7300 LB/H NG OIL	CATALYTIC OXIDATION, GOOD COMBUSTION PRACTICES	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	LA	PSD LA 422	2/13/98	DUCT BURNER	426.00 MMBTU/H	26.0000 PPMV	GOOD DESIGN, PROPER COMBUSTION PRACTICES 3% EXCESS O2	BACT-PSD
BASF CORPORATION	LA	PSD LA 613	12/30/97	DUCT BURNER, COGEN UNIT NO. 2	0.40 MMLB/H STEAM	83.9300 LB/HR	GOOD DESIGN, PROPER OPERATING PRACTICES 2% EXCESS O2	BACT-PSD
COLO. POWER PARTNERS BRUSH COGEN FAC	CO	91MR033	3/27/97	COGEN TURBINES W/ DUCT BURNERS & BOILERS	385.00 MM BTU/HR	39.0000 PPM @ 15% O2	GOOD COMBUSTION	BACT-PSD
MEAD COATED BOARD, INC.	AL	211 0006	8/12/97	DUCT BURNERS	170.00 MMBTU/HR	0.0080 LB/MMBTU	GOOD BURNER DESIGN AND OPERATION	BACT-PSD
GEORGIA GULF CORPORATION	LA	PSD LA 602	3/24/98	DUCT BURNER	460.00 MM BTU/H	600.0000 MM BTU/HR CAP FOR 3	GOOD COMBUSTION PRACTICE AND PROPER OPERATION	BACT-PSD

TABLE 4-2
DIRECT AND INDIRECT CAPITAL COSTS FOR CO CATALYST
SIEMENS WESTINGHOUSE 501 FD COMBINED CYCLE COMBUSTION TURBINE

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$773,000	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk, 1990
Instrumentation	$77,300	10% of SCR Associated Equipment
Sales Tax	$46,380	6% of SCR Associated Equipment/Catalyst
Freight	$38,650	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$979,835	
Direct Installation Costs		
Foundation and supports	$78,387	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	$137,177	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	$39,193	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping	$19,597	2% of TDCC and RCC; OAQPS Cost Control Manual
Insulation for ductwork	$9,798	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	$9,798	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$298,951	
Total Capital Costs	$1,278,786	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$127,879	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$63,939	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$127,879	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$25,576	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$12,788	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$38,364	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$396,424	
Total Direct, Indirect and Capital Costs (TDICC)	$1,675,210	Sum of TCC and TInCC

TABLE 4-3

ANNUALIZED COST FOR CO CATALYST SIEMENS WESTINGHOUSE 501 FD COMBINED CYCLE COMBUSTION TURBINE

Cost Component	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel; OAQPS Cost Control Manual
Catalyst Replacement	$224,667	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$28,292	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,804	3% of Direct Annual Costs
Total Direct Capital Costs (TDCC)	$267,939	
Energy Costs		
Heat Rate Penalty	$222,697	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu additional fuel costs
Total Energy Costs (TDEC)	$222,697	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$16,752	1% of Total Capital Costs
Insurance	$16,752	1% of Total Capital Costs
Annualized Total Direct Capital	$183,938	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$221,748	
Total Annualized Costs	$712,383	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$2,128	Gas-4,760 hrs at 100% load and 3,000 at 60% load;Oil-1,000 hrs 100% load
	$2,267	Net Emission Reduction

Table 4-4. Summary of Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions for Combustion Turbines

Facility Name	State	Permit Number	Permit Issue Date	Unit/Process Description	Capacity (units)	NO_x Emission Limit	Control Method	Basis
KISSIMMEE UTILITIES AUTHORITY	FL	PSD-FL-264	12/16/99	TURBINE, COMBUSTION	250.00 MW	9.0000 PPMVD	GE DLNOX 2.6	BACT PSD
DUKE ENERGY NEW SMYRNA BEACH POWER CO. LP	FL	PSD-FL-267	10/15/99	TURBINE GAS, COMBINED CYCLE	500.00 MW (2 UNITS)	9.0000 PPM @ 15% O2	DLN GE DLN2.6 BURNERS	BACT PSD
TAMPA ELECTRIC COMPANY (TEC)	FL	PSD-FL-263	10/15/99	TURBINE, COMBUSTION, SIMPLE CYCLE	180.00 MW	10.5000 PPM @ 15% O2	DLN GE DLN2.6	BACT PSD
OLEANDER POWER PROJECT	FL	PSD-FL-258	10/1/99	TURBINE GAS, COMBINED CYCLE	180.00 MW	9.0000 PPM @ 15% O2	DLN 2.6 GE ADVANCED DRY LOW NOX BURNERS	BACT PSD
PDC EL PASO MILFORD LLC	CT	105-0066	4/16/99	TURBINE, COMBUSTION, ABB GT-24, #1 WITH 2 CHILLERS	1.87 MMCF/H	2.0000 PPMV @ 15% O2 GAS	SCR WITH AMMONIA INJECTION	LAER
PDC EL PASO MILFORD LLC	CT	105-0066	4/16/99	TURBINE, COMBUSTION, ABB GT 24 #2 WITH 2 CHILLERS	1.87 MMCF/H	2.0000 PPMV @ 15% O2 GAS	SCR WITH AMMONIA INJECTION	LAER
ALABAMA POWER COMPANY - THEODORE COGENERATION	AL	503-8073	3/16/99	TURBINE WITH DUCT BURNER	170.00 MW	0.0130 LB/MMBTU	DLN COMBUSTOR IN CT, LNB IN DUCT BURNER, SCR	BACT PSD
WYANDOTTE ENERGY	MI	278-98	2/8/99	TURBINE, COMBINED CYCLE POWER PLANT	500.00 MW	4.5000 PPM	SCR	BACT
MOBILE ENERGY LLC	AL	503-8068	1/5/99	TURBINE, GAS, COMBINED CYCLE	168.00 MW	0.0180 LB/MMBTU	SCR & DLN COMBUSTORS DURING GAS FIRING STEAM/WATER INJECTION DURING OIL FIRING	BACT PSD
COLORADO SPRINGS UTILITIES	CO	0410030	1/6/99	TURBINE, COMBINE NATURAL GAS FIRED	30.00 MW EACH	15.0000 PPMVD ABOVE 70% LOAD	POLLUTION PREVENTION BUILT INTO EQUIPMENT	BACT PSD
TENASKA GEORGIA PARTNERS, L.P.	GA	4-11-146-0004-P-01-0	12/18/98	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.00 MW EA	15.0000 PPMVD @ 15% O2	USING 15% EXCESS AIR. NOX EMISSION IS BECAUSE OF NATURAL GAS	BACT PSD
TENASKA GEORGIA PARTNERS, L.P.	GA	4-11-146-0004-P-01-0	12/18/98	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.00 MW EA	42.0000 PPM @ 15% O2	USING 15% EXCESS AIR. NOX EMISSION IS BECAUSE OF FUEL OIL	BACT PSD
WESTBROOK POWER LLC	ME	A-719-71-A-N	12/4/98	TURBINE, COMBINED CYCLE, TWO	528.00 MW TOTAL	2.5000 PPM @15% O2	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX BURNERS	LAER
GORHAM ENERGY LIMITED PARTNERSHIP	ME	A-735	12/4/98	TURBINE, COMBINED CYCLE	900.00 MW TOTAL	2.5000 PPM @ 15% O2 (NAT GAS)	SELECTIVE CATALYTIC REDUCTION EMISSION IS FROM EACH 300 MW SYSTEM	LAER
SANTA ROSA ENERGY LLC	FL	PSD-FL-253	12/4/98	TURBINE, COMBUSTION, NATURAL GAS	241.00 MW	9.8000 PPMVD @15% O2 DLN	DRY LOW NOX BURNER	BACT PSD
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/98	GENERATOR, COMBUSTION TURBINE & DUCT BURNER	1998.00 MMBTU/H (CTG)	4.5000 PPMDV @15% O2 (NG)	SELECTIVE CATALYTIC REDUCTION (SCR) WITH A NOX CEM AND A NOX PEM	BACT PSD
CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	ME	A-22-71-N-A	9/14/98	TURBINE, COMBINED CYCLE, NATURAL GAS	175.00 MW	9.0000 PPMVD @15% O2 GAS	DRY LOW NOX BURNER 1 OPTION IS CONSIDERED FOR OIL AND IS SELECTED	BACT PSD
ALABAMA POWER PLANT BARRY	AL	503-1001	8/7/98	TURBINES, COMBUSTION NATURAL GAS	510.00 MW (TOTAL)	0.0130 LB/MMBTU	NATURAL GAS, CT DLN COMBUSTORS, DUCTBURNER LOW NOX BURNER COMBINED STACK SCR	BACT OTHER
TNP TECHN. LLC (FORMERLY TX NM POWER CO.)	NM	PSD-NM-80-M2	8/7/98	GAS TURBINES	376.00 MMBTU/H	15.0000 PPM	WATER INJECTION FOLLOWED BY SELECTIVE CATALYTIC REDUCTION (SCR)	BACT PSD
CASCO BAY ENERGY CO	ME	A-736	7/13/98	TURBINE, COMBINED CYCLE NATURAL GAS, TWO	170.00 MW EACH	3.5000 PPM @15% O2	SELECTIVE CATALYTIC REDUCTION	BACT PSD
CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	FL	PSD-FL-245	7/10/98	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALSO	2171.00 MMBTU/H	25.0000 PPM @ 15% O2	DRY LOW NOX BURNERS FOR SIMPLE CYCLE SCR WHEN COMBINED CYCLE	BACT PSD
COLORADO SPRINGS UTILITIES-NIXON POWER PLANT	CO	94IP932	6/30/98	SIMPLE CYCLE TURBINE, NATURAL GAS	1127.00 MM BTU/H	25.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTION	BACT PSD
BRIDGEPORT ENERGY, LLC	CT	015-0189 & 015-0191	6/26/98	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMENS	260.00 MW PER TURBINE	6.0000 PPM NAT. GAS	DRY LOW NOX BURNER WITH SCR	BACT PSD
CITY OF TALLAHASSEE UTILITY SERVICES	FL	PSD-FL-239	6/26/98	TURBINE, COMBINED CYCLE, MULTIPLE FUELS	1490.00 MMBTU/H	0.0000 SEE F2 DESCRIPTION	DLN BURNERS VERSION 2.6 BY GE	BACT PSD
GENERAL ELECTRIC PLASTICS	AL	707-0008-X019	6/27/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)	0.00	0.0700 LB/MMBTU COMBINED	DRY LOW NOX BURNER ON TURBINE AND LOW NOX BURNER ON DUCT BURNER	BACT OTHER
RUMFORD POWER ASSOCIATES	ME	A-226-71-A-N	6/1/98	TURBINE GENERATOR, COMBUSTION, NATURAL GAS	1808.00 MMBTU/H	3.5000 PPM @ 15% O2	SCR AMMONIA INJECTION SYSTEM AND CATALYTIC REACTOR TO REDUCE NOX	BACT PSD
ANDROSCOGGIN ENERGY LIMITED	ME	A-316-71-A-N	3/31/98	GAS TURBINES, COGEN, W/DUCT BURNERS	670.00 MMBTU/H TURBINE	9.0000 PPM @ 15% O2 NG	LOW NOX BURNERS, LOW NOX COMBUSTORS, SCR DURING GAS FIRING ONLY.	BACT PSD
ANDROSCOGGIN ENERGY LIMITED	ME	A-316-71-A-N	3/31/98	GAS TURBINES, COGEN, W/DUCT BURNERS	670.00 MMBTU/H TURBINE	42.0000 PPM @ 15% O2 NG OIL	LOW NOX COMBUSTORS, LOW NOX BURNERS, WATER INJECTION DURING OIL FIRING	BACT PSD
STAR ENTERPRISE	DE	APC-81/0603-CONST A-AMEND	3/30/98	TURBINES, COMBINED CYCLE 2	828.80 MMBTU/H	10.0000 PPM @ 15% O2 SYN GAS	NITROGEN INJECTION WHILE FIRING SYNGAS AND STEAM INJECTION WHILE FIRING LSDF	LAER
STAR ENTERPRISE	DE	APC-81/0603-CONST A-AMEND	3/30/98	TURBINES, COMBINED CYCLE 2	828.80 MMBTU/H	42.0000 PPM @ 15% O2 DIESEL	NITROGEN INJECTION WHILE FIRING SYNGAS AND STEAM INJECTION WHILE FIRING LSDF	LAER
SOUTHERN NATURAL GAS	AL	412-0013-X001 AND X002	3/4/98	2-8180 HP GE MODEL MS3002G NATURAL GAS TURBINES	8180.00 HP	53.0000 LB/H		BACT PSD
SOUTHERN NATURAL GAS	AL	306-0021-X001 AND X002	3/4/98	8180 HP GE MODEL MS3002G NATURAL GAS FIRED TURBINE	8180.00 HP	53.0000 LB/H		BACT PSD
TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	WY	CT-1352	2/27/98	TURBINE, STATIONARY	33.30 MW	25.0000 PPM @ 15% O2	DRY LOW NOX BURNERS	BACT PSD
AIR LIQUIDE AMERICA CORPORATION	LA	PSD-LA-627	2/13/98	TURBINE GAS, GE 7MA 7	999.00 MMBTU/H	9.0000 PPMV	DRY LOW NOX TO LIMIT NOX EMISSION TO 9PPMV	BACT PSD
TIVERTON POWER ASSOCIATES	RI	RI-PSD-4	2/13/98	COMBUSTION TURBINE, NATURAL GAS	265.00 MW	3.5000 PPM @ 15% O2	SCR	LAER
MILLENNIUM POWER PARTNERS, LP	MA	130821	2/2/98	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2534.00 MMBTU/H	0.0130 LB/MMBTU	DRY LOW NOX COMBUSTION TECHNOLOGY IN CONJUNCTION WITH SCR ADD-ON NOX CONTROLS	LAER
BASF CORPORATION	LA	PSD-LA-613	12/30/97	TURBINE, COMBINED UNIT 2, GE FRAME 6	42.40 MW	8.0000 PPMV NAT. GAS	STEAM INJECTION AND SCR TO LIMIT NOX TO 8 PPM FOR NATURAL GAS AND 29 PPM FOR WASTE GAS (80% H2)	BACT PSD
ALABAMA POWER COMPANY	AL	108-0018-X001 AND X002	12/17/97	COMBUSTION TURBINE W/ DUCT BURNER (COMBINED CYCLE)	100.00 MW	15.0000 PPM	DRY LOW NOX BURNERS	BACT OTHER
BUCKNELL UNIVERSITY	PA	60-0001A	11/26/97	NG FIRED TURBINE, SOLAR TAURUS T 7300S	5.00 MW	25.0000 PPMV@15% O2	SOLONOX BURNER, LOW NOX BURNER	BACT PSD
DIGHTON POWER ASSOCIATE, LP	MA	4B96046	10/6/97	TURBINE, COMBUSTION, ABB GT 11N2	1327.00 MMBTU/H	13.1200 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-ON NOX CONTROL.	BACT PSD
NORTHERN CALIFORNIA POWER AGENCY	CA	N-6031-1	10/2/97	GE FRAME 5 GAS TURBINE	325.00 MMBTU/HR	25.0000 PPMVD @ 15% O2	DRY LOW NOX BURNERS	BACT PSD
QUESTAR PIPELINE CORP. - ROCK SPRINGS COMPRESSOR COM	WY	MD-333	9/25/97	TURBINE COMPRESSOR ENGINE, NATURAL GAS FIRED, 25A	1001.00 HP	2.8200 G/B-HP-H		LAER
BERKSHIRE POWER DEVELOPMENT, INC	MA	1-X-96-093	8/22/97	ENGINE & CHILLER NATURAL GAS FIRED, TWO	23.40 MMBTU/H	0.7000 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD ON NOX CONTROL.	BACT PSD
BERKSHIRE POWER DEVELOPMENT, INC.	MA	1-X-96-093	8/22/97	TURBINE COMBUSTION, ABB GT24	1792.00 MMBTU/H	20.5000 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD ON NOX CONTROL.	BACT PSD
UNIVERSITY OF MEDICINE & DENTISTRY OF NEW JERSEY	NJ	08742/28/29 (3)	6/26/97	COMBUSTION TURBINE COGENERATION UNIT 3	64.00 MMBTU/H	0.1970 LB/MMBTU NAT.GAS		BACT PSD
LORDSBURG L.P.	NM	PSD-NM-1975	6/18/97	TURBINE NATURAL GAS FIRED, ELEC. GEN.	100.00 MW	74.4000 LB/H	DRY LOW NOX TECHNOLOGY WHICH ADOPTS STAGED OR SCHEDULED COMBUSTION	BACT
SOUTHERN CALIFORNIA GAS COMPANY	CA	S-1787-6-3	5/14/97	VARIABLE LOAD NATURAL GAS FIRED TURBINE COMPRESSOR	50.10 MMBTU/H	25.0000 PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR	BACT PSD
COLO. POWER PARTNERS-BRUSH COGEN FAC	CO	91MR933	3/27/97	COGEN TURBINES W/ DUCT BURNERS & BOILERS	395.00 MM BTU/H	42.0000 PPM @ 15% O2	LOW NOX COMBUSTION RETROFIT AND WATER INJECTION	LAER
MEAD COATED BOARD, INC.	AL	211-0004	3/12/97	COMBINED CYCLE TURBINE (25 MW)	590.00 MMBTU/H	25.0000 PPMVD@ 15% O2 (GAS)	F.O. OIL SULFUR CONTENT < =0.05% BY WT DLN NOX FIRING GAS WITH WATER INJECTION FIRING OIL	BACT PSD
FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	LA	PSD-LA-560-M 21	3/7/97	TURBINE/HRSG, GAS COGENERATION	450.00 MM BTU/H	9.0000 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONSTRUCTION.	BACT PSD
QUINCY SOYBEAN COMPANY OF ARKANSAS	AR	800-AOP-R0	3/4/97	BOILER, COGENERATION/WASTE HEAT RECOVERY	48.00 MMBTU/H	25.0000 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT PSD
SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	NM	PSD-NM-427-M 2	2/15/97	COMBUSTION TURBINE, NATURAL GAS	100.00 MW	0.0000 SEE FACILITY NOTES	DRY LOW NOX COMBUSTION	BACT PSD
CALRESOURCES LLC	CA	S-1043-6-1 AND 6-3	1/10/97	SOLAR MODEL 1100 SATURN GAS TURBINE	13.80 MMBTU/H	88.0000 PPMVD @15% O2	NO CONTROL	LAER
TEMPO PLASTICS	CA	S-896-5-0	12/31/96	GAS TURBINE COGENERATION UNIT	0.00	0.1080 LB/MMBTU	LOW NOX COMBUSTOR	LAER
SOUTHERN NATURAL GAS COMPANY	MS	1300-00031	12/17/96	TURBINE, NATURAL GAS FIRED	8180.00 HORSEPOWER	110.0000 PPMV @ 15% O2 DRY	PROPER TURBINE DESIGN AND OPERATION	BACT PSD
SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	NM	PSD-NM-632-M 1	11/4/96	COMBUSTION TURBINE, NATURAL GAS	100.00 MW	15.0000 PPM SEE FAC. NOTES	DRY LOW NOX COMBUSTION	BACT PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED CYCLE COGENERATION	461.00 MW	73.0000 LB/H	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR)	BACT PSD
ECOELECTRICA, L.P.	PR	PR-0102	10/1/96	TURBINES, COMBINED CYCLE COGENERATION	461.00 MW	80.0000 LB/H	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR)	BACT PSD
TOYOTA MOTOR CORPORATION SVCS OF N.A.	IN	CP-051-6381-00037	9/6/96	PLANTWIDE COMBUSTION UNITS	1460.00 MMBTU/H	0.1300 LB/MMBTU	FUEL SPEC: USE OF NATURAL GAS AS FUEL.	BACT PSD
BLUE MOUNTAIN POWER, LP	PA	06-328-006	7/31/96	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	162.00 MW	4.0000 PPM @ 15% O2	DRY LNB WITH SCR WATER INJECTION FOR OIL FIRING. OIL FIRING LIMITS SET TO 8.4 PPM @15% O2	LAER
WESTPLAINS ENERGY	CO	95PB019	6/14/96	SIMPLE CYCLE TURBINE, NATURAL GAS	218.50 MW	15.0000 PPM @ 15% O2 (@>75%)	DLN NOX, COMMITMENT TO UPGRADE THE DLN TO NEW VERSIONS (ATTAINING LOWER NOX) AS THEY BECOME AVAILABLE	BACT PSD
PUBLIC SERVICE OF COLO.-FORT ST VRAIN	CO	94WE606	5/1/96	COMBINED CYCLE TURBINES (2) NATURAL	471.00 MW	15.0000 PPMVD SIMPL CY	DRY LOW NOX COMBUSTION SYSTEMS FOR TURBINES AND DUCT BURNERS	BACT PSD
CAROLINA POWER & LIGHT	NC	1812	4/11/96	COMBUSTION TURBINE, 4 EACH	1907.00 MMBTU/H	612.3000 LB/H	WATER INJECTION, FUEL SPEC: 0.04% N FUEL OIL	BACT PSD
CAROLINA POWER & LIGHT	NC	1812	4/11/96	COMBUSTION TURBINE, 4 EACH	1907.00 MMBTU/H	158.0000 LB/H	WATER INJECTION	BACT PSD
MID GEORGIA COGEN.	GA	4911-078-11783	4/3/96	COMBUSTION TURBINE (2) NATURAL GAS	118.00 MW	9.0000 PPMVD	DRY LOW NOX BURNER WITH SCR	BACT PSD
MID GEORGIA COGEN.	GA	4911-078-11783	4/3/96	COMBUSTION TURBINE (2), FUEL OIL	118.00 MW	20.0000 PPMVD	WATER INJECTION WITH SCR	BACT PSD
GEORGIA GULF CORPORATION	LA	PSD-LA-592	3/26/96	GENERATOR, NATURAL GAS FIRED TURBINE	1123.00 MM BTU/H	25.0000 PPMV CORR. TO 15% O2	CONTROL NOX USING STEAM INJECTION	BACT PSD
SEMINOLE HARDEE UNIT 3	FL	PA-95-26A / PSD-FL-214	1/1/96	COMBINED CYCLE COMBUSTION TURBINE	140.00 MW	15.0000 PPM @ 15% O2	DRY LNB STAGED COMBUSTION	BACT PSD
MINNESOTA METHANE	AZ	95-0241	11/12/95	ENGINES, COGENERATION (4)	800.00 KW	60.0000 TPY	AIR/FUEL CONTROLLER ADJUSTED TO OBTAIN LOW NOX	BACT
KEY WEST CITY ELECTRIC SYSTEM	FL	AC44-245300 / PSD-FL-210	9/28/95	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23.00 MW	75.0000 PPM @ 15% O2	WATER INJECTION	BACT PSD
UNION CARBIDE CORPORATION	LA	PSD-LA-590	9/22/95	GENERATOR, GAS TURBINE	1313.00 MM BTU/H	25.0000 PPMV CORR. TO 15% O2	DRY LOW NOX COMBUSTOR	BACT PSD
PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	PR	PR-0100	7/31/95	COMBUSTION TURBINES (3), 83 MW SIMPLE CYCLE EACH	248.00 MW	35.0000 LB/H AS NO2	STEAM INJECTION PLUS SCR SYSTEM. USE OF NO. 2 F.O. NITROGEN CONTENT NOT TO EXCEED 0.10% BY WEIGHT.	BACT PSD
HIGGINSVILLE MUNICIPAL POWER FACILITY	MO	0795-0023	7/27/95	ADD OF A DUAL FUEL FIRED TWIN PAC TURBINE	48.10 MW	42.0000 PPM BY VOL 1 HR AVG	CONTROLS TO REGULATE THE FUEL CONSUMPTION AND THE RATIO OF WATER TO FUEL BEING FIRED IN THE TURBINES	BACT PSD
HIGGINSVILLE MUNICIPAL POWER FACILITY	MO	0795-0023	7/27/95	ADD OF A DUAL FUEL FIRED TWIN PAC TURBINE	48.10 MW	36.0000 PPM BY VOL 1 HR AVG	CONTROLS TO REGULATE THE FUEL CONSUMPTION AND THE RATIO OF WATER TO FUEL BEING FIRED IN THE TURBINES	BACT PSD
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	2-6101-00108/00007-0	6/6/95	TURBINE, OIL FIRED	240.00 MW	10.0000 PPM @ 15% O2	SCR	LAER
BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NY	2-6101-00108/00007-0	6/6/95	TURBINE NATURAL GAS FIRED	240.00 MW	3.5000 PPM @ 15% O2	SCR	LAER
PANDA KATHLEEN, L.P.	FL	AC53-251096/PSD-FL-210	6/1/95	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75.00 MW	15.0000 PPM @ 15% O2	DRY LOW NOX BURNER	BACT PSD
PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	PA	66-0001	5/31/95	TURBINE, NATURAL GAS	580.00 MMBTU/H	55.0000 PPM @ 15% O2	STEAM INJECTION	BACT
HOFFMAN LA ROCHE NUTLEY COGEN FACILITY	NJ	SEE FACILITY NOTES	5/5/95	TURBINE, GE LM500	56.80 MMBTU/H	0.3400 LB/MMBTU		BACT
GAINESVILLE REGIONAL UTILITIES	FL	PSD-FL-212	4/11/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B/UP	74.00 MW	15.0000 PPM AT 15% OXYGEN	DRY LOW NOX BURNERS GE FRAME UNIT, CAN ANNULAR COMBUSTORS	BACT PSD
GAINESVILLE REGIONAL UTILITIES	FL	PSD-FL-212	4/11/95	OIL FIRED COMBUSTION TURBINE	74.00 MW	42.0000 PPM AT 15% OXYGEN	WATER INJECTION	BACT PSD
ALGONQUIN GAS TRANSMISSION COMPANY	NJ	LOOP 94-0079	3/31/95	TURBINES COMBUSTION, TWO SOLAR CENTAUR	2.10 MW EACH	0.0000 NOT APPLICABLE	GOOD COMBUSTION PRACTICE	BACT
ALGONQUIN GAS TRANSMISSION COMPANY	NJ	LOOP 94-0079	3/31/95	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.10 MW EACH	43.3800 LB/H		BACT
FORMOSA PLASTICS CORPORATION, LOUISIANA	LA	PSD-LA-560 (M-1)	3/2/95	TURBINE/HRSG, GAS COGENERATION	450.00 MM BTU/H	9.0000 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONTROL	BACT
LSP COTTAGE GROVE, L.P.	MN	16300087-001	3/1/95	COMBUSTION TURBINE/GENERATOR	1970.00 MMBTU/H	4.5000 PPM @ 15% O2 GAS	SELECTIVE CATALYTIC REDUCTION (SCR)	LAER
EMPIRE DISTRICT ELECTRIC CO.	MO	0395-016	2/28/95	INSTALL TWO NEW SIMPLE CYCLE TURBINES	88.77 MW	380.0000 TPY	WATER INJECTION	BACT PSD
MARATHON OIL CO. - INDIAN BASIN N.G. PLANT	NM	PSD-NM-295-M 2	1/11/95	TURBINES, NATURAL GAS (2)	5500.00 HP	7.4000 LB/H	LEAN PREMIXED COMBUSTION TECHNOLOGY DRY/LOW NOX	BACT PSD
KAMINE/BESICORP SYRACUSE LP	NY	313201 2010/00001-00007	12/10/94	SIEMENS V84.2 GAS TURBINE (EP #00001)	650.00 MMBTU/H	25.0000 PPM	WATER INJECTION	BACT PSD
INDECK OSWEGO ENERGY CENTER	NY	351200 0211 00001	10/6/94	GE FRAME 6 GAS TURBINE	633.00 LB/MMBTU	42.0000 PPM, 25.00 LB/H	STEAM INJECTION	BACT
SEPCO	CA	10003	10/5/94	TURBINE GAS COMBINED CYCLE GE MODEL 7	820.00 MMBTU/H	2.5000 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX COMBUSTION	BACT
FULTON COGEN PLANT	NY	380400 0221 00001	8/15/94	GE LM5000 GAS TURBINE	600.00 MMBTU/H	39.0000 PPM, 85 LB/H	WATER INJECTION	BACT
CAROLINA POWER AND LIGHT	SC	0820-0033	8/31/94	STATIONARY GAS TURBINE	1820.00 MMBTU/H	42.0000 PPMDV @ 15% O2	WATER INJECTION	BACT PSD
CAROLINA POWER AND LIGHT	SC	0820-0033	8/31/94	STATIONARY GAS TURBINE	1820.00 MMBTU/H	25.0000 PPMDV @ 15% O2	WATER INJECTION	BACT PSD
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	CA	11458	8/19/94	TURBINE GAS, COMBINE CYCLE SIEMENS V84.2	1257.00 MMBTU/H	3.0000 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX COMBUSTION	BACT
BEAR MOUNTAIN LIMITED	CA	S-2049-1-2	8/16/94	TURBINE, GE, COGENERATION 48 MW	48.00 MW	3.6000 PPMVD @ 15% O2	STEAM INJECTION AND SELECTIVE CATALYTIC REDUCTION	BACT OTHER
SACRAMENTO COGENERATION AUTHORITY P&G	CA	11430	8/19/94	TURBINE, SIMPLE CYCLE LM6000 GAS	421.40 MMBTU/H	5.0000 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION	BACT
SACRAMENTO COGENERATION AUTHORITY P&G	CA	11430	8/19/94	TURBINE, GAS, COMBINED CYCLE LM6000	421.40 MMBTU/H	5.0000 PPM @ 15% O2	SELECTIVE CATAYTIC REDUCTION AND WATER INJECTION	BACT
SACRAMENTO COGENERATION AUTHORITY P&G	CA	11430	8/19/94	TURBINE, GAS, COMBINED CYCLE LM6000	421.40 MMBTU/H	3.0000 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION	BACT
SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	CA	11458	8/19/94	TURBINE, GAS, COMBINED CYCLE SIEMENS V84.2	1257.00 MMBTU/H	3.0000 PPMVD @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX COMBUSTION	BACT
HERMISTON GENERATING CO.	OR	30-0113	7/7/94	TURBINES, NATURAL GAS (2)	1696.00 MMBTU/H	4.5000 PPM @ 15% O2	SCR	BACT PSD
MUDDY RIVER L.P.	NV	A0113	6/10/94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140.00 MEGAWATT	303.0000 LB/H	LOW NOX BURNER	BACT PSD
CSW NEVADA, INC.	NV	A0116	6/10/94	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140.00 MEGAWATT	273.0000 LB/H	DRY LOW NOX COMBUSTOR	BACT PSD
PORTLAND GENERAL ELECTRIC CO.	OR	26-0031	5/31/94	TURBINES, NATURAL GAS (2)	1720.00 MMBTU	4.5000 PPM @ 15% O2	SCR	BACT PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	0594-026	5/17/94	INSTALL TWO NEW SIMPLE CYCLE TURBINES	1345.00 MMBTU/HR	26.0000 PPM BY VOL 1 HR AVG	LOW NOX BURNERS AND WATER INJECTION	BACT PSD
EMPIRE DISTRICT ELECTRIC CO.	MO	0594-026	5/17/94	INSTALL TWO NEW SIMPLE CYCLE TURBINES	1345.00 MMBTU/HR	1136.0000 TPY	LOW NOX BURNERS AND WATER INJECTION	BACT PSD
GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	GA	4911-076-11348	5/13/94	TURBINE, COMBUSTION, NATURAL GAS	80.00 MW	26.0000 PPM	WATER INJECTION, FUEL SPEC: NATURAL GAS	BACT PSD
WEST CAMPUS COGENERATION COMPANY	TX	23062/PSD-TX-837	5/2/94	GAS TURBINES	75.30 MW (TOTAL POWER)	200.0000 TPY	INTERNAL COMBUSTION CONTROLS	BACT PSD
FLEETWOOD COGENERATION ASSOCIATES	PA	06-328-001	4/22/94	NO TURBINE (GE LM6000) WITH WASTE HEAT BOILER	380.00 MMBTU/H	21.0000 LB/H	SCR WITH LOW NOX COMBUSTORS	BACT OTHER
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE NATURAL GAS (2)	1510.00 MMBTU/H	12.0000 PPMVD @15% O2	DRY LOW NOX COMBUSTOR	BACT PSD
FLORIDA POWER CORPORATION POLK COUNTY SITE	FL	PSD-FL-195	2/25/94	TURBINE, FUEL OIL (2)	1730.00 MMBTU/H	42.0000 PPMVD @ 15% O2	WATER INJECTION	BACT PSD
INTERNATIONAL PAPER	LA	PSD-LA-63(M-3)	2/24/94	TURBINE/HRSG, GAS COGEN	338.00 MM BTU/H/ TURBINE	25.0000 PPMV 15% O2 TURBINE	DRY LOW NOX COMBUSTOR/COMBUSTION CONTROL	BACT
TECO POLK POWER STATION	FL	PSD-FL-194	2/24/94	TURBINE, SYNGAS (COAL GASIFICATION)	1755.00 MMBTU/H	25.0000 PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR	BACT PSD
TECO POLK POWER STATION	FL	PSD-FL-194	2/24/94	TURBINE FUEL OIL	1755.00 MMBTU/H	42.0000 PPMVD @ 15% O2	WET INJECTION	BACT PSD
KAMINE/BESICORP CARTHAGE L.P.	NY	224001 0296 00001	1/18/94	GE FRAME 6 GAS TURBINE	481.00 BTU/H	42.0000 PPM, 76.6 LB/H	STEAM INJECTION	BACT
SUNLAW COGEN. (FEDERAL COLD STORAGE COGENERATION)	CA	RECLAIM 56711	1/18/94	TURBINE NATURAL GAS FIRED COMBINED CYCLE AND COG	28.00 MW	1068117.0000 LB/YR	WATER INJECTION AND SCONOX (MOD 2) CATALYST SYSTEM IS INSTALLED AFTER THE HRSG	BACT OTHER
ORANGE COGENERATION LP	FL	PSD-FL-206	12/30/93	TURBINE, NATURAL GAS, 2	368.30 MMBTU/H	15.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT PSD
PROJECT ORANGE ASSOCIATES	NY	311800 2015 00001	12/1/93	GE LM 6000 GAS TURBINE	660.00 MMBTU/H	25.0000 PPM, 41 LB/H	STEAM INJECTION, FUEL SPEC: NATURAL GAS ONLY	BACT
WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	NM	PSD-NM-2400	10/29/93	TURBINE, GAS-FIRED	11257.00 HP	42.0000 PPM @ 15% O2	SOLONOX COMBUSTOR, DRY LOW NOX TECHNOLOGY	BACT PSD
CROCKETT COGENERATION - C&H SUGAR	CA	S-201	10/6/93	TRUBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA)	240.00 MW	2.5000 PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR(S) AND A MITSUBISHI HEAVY INDUSTRIES AMERICAN SELECTIVE CATALYTIC REDUCTION CATALYST	BACT OTHER
FLORIDA GAS TRANSMISSION	FL	FL-PSD-202	9/27/93	TURBINE, GAS	131.80 MMBTU/H	26.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT PSD
PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	VA	71975	9/15/93	TURBINE, COMBUSTION, SIEMENS MODEL V84.2 3	10.20 X106 SCF/YR NAT GAS	131.0000 LB/H (GAS) - 330 OIL	DRY LOW NOX COMBUSTOR- DESIGN WATER INJECTION	BACT PSD
FLORIDA GAS TRANSMISSION COMPANY	AL	503-3028-X003	8/6/93	TURBINE, NATURAL GAS	12600.00 BHP	0.5800 G/BHP-HR	AIR TO FUEL RATIO CONTROL, DRY LOW NOX COMBUSTION	BACT PSD
CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING AUT	CA	11012	7/23/93	TURBINE, GAS, COMBINED CYCLE, GE LM6000	450.00 MMBTU/H	5.0000 PPMVD @ 15% O2	SCR AND WATER INJECTION ALSO HAS CARBON ABSORPTION SYSTEM IN DIGESTER TO REMOVE ORGANSILOXANES	BACT
CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING AUT	CA	11012	7/23/93	TURBINE, GAS, SIMPLE CYCLE, GE LM6000	450.00 MMBTU/H	5.0000 PPMVD @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION	BACT
LOCKPORT COGEN FACILITY	NY	292900 0448/00001-00007	7/14/93	(6) GE FRAME 6 TURBINES (EP #00001-00006)	423.80 MMBTU/H	42.0000 PPM	STEAM INJECTION	BACT
AMTEC COGEN PLANT	NY	030200 0461	7/7/93	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451.00 MMBTU/H	36.0000 PPM, 41 LB/H	NO CONTROLS	BACT OTHER
BANK OF AMERICA LOS ANGELES DATA CENTER	CA	A/N 272890	6/24/93	TURBINE, DIESEL & GENERATOR (SEE NOTES)	0.00	163.0000 PPM @ 15% O2	FUEL SPEC: LOW NOX DIESEL FUEL (SEE NOTES)	BACT OTHER
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-6231 TO01-92-6261	6/9/93	TURBINES, COMBUSTION NATURAL GAS-FIRED (2)	617.00 MMBTU/H EACH	8.3000 PPMDV	SCR	BACT PSD
NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NJ	01-92-6231 TO01-92-6261	6/9/93	TURBINES, COMBUSTION, KEROSENE-FIRED (2)	660.00 MMBTU/H EACH	18.0000 PPMDV	SCR	BACT PSD
TIGER BAY LP	FL	PSD-FL-180	5/17/93	TURBINE, GAS	1614.00 MMBTU/H	15.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT PSD
TIGER BAY LP	FL	PSD-FL-180	5/17/93	TURBINE, OIL	1949.00 MMBTU/H	42.0000 PPM @ 15% O2	WATER INJECTION	BACT PSD
INDECK ENERGY COMPANY	NY	581203 0000	5/13/93	GE FRAME 6 GAS TURBINE EP #00001	481.00 MMBTU/H	32.0000 PPM	STEAM INJECTION	BACT
PHOENIX POWER PARTNERS	CO	92WE087	5/11/93	TURBINE NATURAL GAS	311.00 MMBTU/H	22.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTION	BACT OTHER
LILCO SHOREHAM	NY	472200 5376	5/10/93	(2) GE FRAME 7 TURBINES (EP #00007-8)	880.00 MMBTU/H	65.0000 PPM +FUN & HEAT RATE	WATER INJECTION	BACT
TRIGEN MITCHEL FIELD	NY	282000 4163 00004	4/16/93	GE FRAME 6 GAS TURBINE	434.70 MMBTU/H	60.0000 PPM, 60 LB/H	STEAM INJECTION	BACT
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	899.00 MMBTU/H	15.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, NATURAL GAS	367.00 MMBTU/H	15.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT PSD
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD-182	4/7/93	TURBINE, FUEL OIL	979.00 MMBTU/H	42.0000 PPM @ 15% O2	WATER INJECTION	BACT PSD

Table 4-4. Summary of Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions for Combustion Turbines

Facility Name	State	Permit Number	Permit Issue Date	Unit/Process Description	Capacity (units)	NO_x Emission Limit	Control Method	Basis
KISSIMMEE UTILITY AUTHORITY	FL	FL-PSD 182	4/7/03	TURBINE, FUEL OIL	371.00 MMBTU/H	42.0000 PPM @ 15% O2	WATER INJECTION	
EAST KENTUCKY POWER COOPERATIVE	KY	C 02 048	3/24/03	TURBINES (4), #2 FUEL OIL AND NAT. GAS FIRED	1492.00 MMBTU/H (EACH)	42.0000 PPM @ 15% O2 (OIL)	WATER INJECTION	BACT-PSD
INTERNATIONAL PAPER CO. RIVERDALE MILL	AL	104 0003 X029	1/11/03	TURBINE, STATIONARY (GAS FIRED) WITH DUCT BURNER	40.00 MW	0.0800 LB/MMBTU (GAS)	LOW NOX BURNERS (ON THE DUCT BURNER) STEAM INJECTION INTO THE TURBINE	SEE NOTES
OKLAHOMA MUNICIPAL POWER AUTHORITY	OK	02-016-C (PSD)	12/17/02	TURBINE, COMBUSTION	58.00 MW	65.0000 PPM @ 15% O2	COMBUSTION CONTROLS	BACT-PSD
OKLAHOMA MUNICIPAL POWER AUTHORITY	OK	02-016-C (PSD)	12/17/02	TURBINE, COMBUSTION	58.00 MW	75.0000 PPM @ 15% O2	COMBUSTION CONTROLS	BACT-OTHER
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/02	TURBINE, GAS	1214.00 MMBTU/H	15.0000 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	BACT-OTHER
AUBURNDALE POWER PARTNERS, LP	FL	PSD-FL-185	12/14/02	TURBINE, OIL	1170.00 MMBTU/H	42.0000 PPMVD @ 15 % O2	STEAM INJECTION	BACT-PSD
SITHE/INDEPENDENCE POWER PARTNERS	NY	7-3556-00040/00001-0	11/24/02	TURBINES, COMBUSTION (4) NATURAL GAS (1012 MW)	2133.00 MMBTU/HR (EACH)	4.5000 PPM	SCR AND DRY LOW NOX	BACT-PSD
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	6-2370-00016/00001-0	11/6/02	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (70MW)	980.00 MMBTU/HR	55.0000 PPM	DRY LOW NOX OR SCR	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	6-2370-00016/00001-0	11/6/02	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (70MW)	690.00 MMBTU/HR	6.0000 PPM	DRY LOW NOX OR SCR	BACT-OTHER
KAMINE/BESICORP CORNING L.P.	NY	8-4538-00023/010	11/5/02	TURBINE, COMBUSTION (70 MW)	853.00 MMBTU/HR	6.0000 PPM	DRY LOW NOX OR SCR	BACT-OTHER
GRAYS FERRY CO. GENERATION PARTNERSHIP	PA	92101 TO 92104	11/4/02	TURBINE (NATURAL GAS & OIL)	1160.00 MMBTU	9.0000 PPMVD (NAT. GAS)*	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER
GOAL LINE LP ICEFLOE	CA	911804	11/3/02	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)	388.00 MMBTU/HR	9.0000 PPMVD @ 15% OXYGEN	WATER INJECTION & SCR W/ AUTOMATIC AMMONIA INJECT	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	VA	50840	10/30/02	TURBINE, COMBUSTION GAS	474.00 X10(6) BTU/HR N. GAS	9.0000 PPM	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	VA	50840	10/30/02	TURBINE, COMBUSTION OIL	498.00 X10(6) BTU/HR #2 OIL	15.0000 PPM	SCR	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	50840	10/30/02	TURBINE, COMBUSTION GAS (TOTAL)	0.00	89.7000 TPY	SCR	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	REGISTRATION # 40806	8/26/02	TURBINE FACILITY, GAS	1321.13 X10(6) BCF/Y NAT GAS	245.0000 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR) W/ WATER INJEC	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	REGISTRATION # 40806	8/26/02	TURBINE FACILITY, GAS	7.44 X10(3) GPY FUEL OIL	245.0000 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	REGISTRATION # 40806	8/26/02	TURBINES (2) (EACH WITH A DB)	5.51 X10(6) BTU/H N GAS	9.0000 PPMDV/UNIT @ 15% O2	SCR WITH WATER INJECTION	BACT-PSD
GORDONSVILLE ENERGY L.P.	VA	REGISTRATION # 40806	8/26/02	TURBINES (2) (EACH WITH A DB)	1.36 X10(6) BTU/H #2 OIL	65.0000 LB/H/UNIT	WATER INJECTION AND SCR	BACT-PSD
NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	NV	A633	8/16/02	COMBUSTION TURBINE ELECTRIC POWER GENERATION	800.00 MW (8 UNITS 75 EACH)	88.0000 TPY (EACH TURBINE)	LOW NOX COMBUSTOR	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	NY	414401 0212 00001	8/10/02	GE FRAME 6 GAS TURBINE	498.00 MMBTU/H	42.0000 PPM, 78.8 LB/H	WATER INJECTION	BACT-PSD
NORTHERN STATES POWER COMPANY	SD	NONE	8/2/02	TURBINE, SIMPLE CYCLE, 4 EACH	120.00 MW	24.0000 PPM @ 15% O2 GAS	WATER INJECTION FOR GAS & DISTILLATION	BACT
PAINTANOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00826/00001-4	8/1/02	TURBINE, COMBUSTION GAS (160 MW)	1140.00 MMBTU/HR (GAS)*	42.0000 PPM	WATER INJECTOR	BACT-PSD
PAINTANOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00826/00001-4	8/1/02	TURBINE, COMBUSTION GAS (160 MW)	1140.00 MMBTU/HR (GAS)*	8.0000 PPM	DRY LOW NOX	BACT-OTHER
PAINTANOLTSVILLE COMBINED CYCLE PLANT	NY	1-4722-00826/00001-4	8/1/02	GENERATOR, EMERGENCY (NATURAL GAS)	1.50 MMBTU/HR	1.3000 LB/MMBTU	LEAN BURN ENGINE	BACT-OTHER
WEPCO, PARIS SITE	WI	01-RV-043	8/20/02	TURBINES, COMBUSTION (4)	0.00	85.0000 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-OTHER
WEPCO, PARIS SITE	WI	01-RV-043	8/20/02	TURBINES, COMBUSTION (4)	0.00	25.0000 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
FLORIDA POWER CORPORATION	FL	FL-PSD 180	8/17/02	TURBINE, OIL	1029.00 MMBTU/H	42.0000 PPMVD @ 15 % O2	WET INJECTION	BACT-PSD
FLORIDA POWER CORPORATION	FL	FL-PSD 180	8/13/02	TURBINE, GAS	1866.00 MMBTU/H	42.0000 PPMVD @ 15 % O2	WET INJECTION	BACT-PSD
NORTHWEST PIPELINE COMPANY	WA	024	8/13/02	TURBINE, GAS FIRED	12100.00 HP	100.0000 PPM @ 15% O2	ADVANCED DRY LOW NOX COMBUSTOR (BY 07/01/05)	BACT-PSD
CNG TRANSMISSION	OH	01-3870	8/12/02	TURBINE (NATURAL GAS) (3)	9600.00 HP (EACH)	1.0000 G/HP-HR*	LOW NOX COMBUSTION	BACT-PSD
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-0	7/31/02	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123.00 MMBTU/HR (EACH)	9.0000 PPM	SCR	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10841	7/26/02	TURBINE, GAS FIRED (2 EACH)	1617.00 M BTU/HR	25.0000 PPM @ 15% O2	MAXIMUM WATER INJECTION	BACT-OTHER
HARTWELL ENERGY LIMITED PARTNERSHIP	GA	4911-073-10841	7/26/02	TURBINE, OIL FIRED (2 EACH)	1840.00 M BTU/HR	25.0000 PPMVD FUEL N ALLOW	MAXIMUM WATER INJECTION	BACT-PSD
MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	HI	HI 80-06	7/26/02	TURBINE, COMBINED CYCLE COMBUSTION	28.00 MW	47.3000 LB/H	WATER INJECTION	BACT-PSD
INDECK-YERKES ENERGY SERVICES	NY	146400 0133	6/24/02	GE FRAME 6 GAS TURBINE (EP 00001)	432.30 MMBTU/HR	42.0000 PPM, 74 LB/H	STEAM INJECTION	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-8	6/18/02	COMBUSTION TURBINES (2) (262 MW)	1173.00 MMBTU/HR (EACH)	9.0000 PPM GAS	STEAM INJECTION AND SCR	BACT
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-9	6/18/02	COMBUSTION TURBINE (79 MW)	1173.00 MMBTU/HR	25.0000 PPM GAS	STEAM INJECTION	BACT-OTHER
TENASKA WASHINGTON PARTNERS, L.P.	WA	91-04	6/26/02	COGENERATION PLANT, COMBINED CYCLE	1.83 MMBTU/HR	7.0000 PPM @ 15% O2 (GAS)	STAGED LOW NOX DUCT BURNERS, STEAM INJECTION SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-OTHER
NORTHWEST PIPELINE CORPORATION	CO	01LP7921(1-3) MOD. #1	5/28/02	TURBINE, SOLAR TAURUS	45.00 MMBTU/HR	65.0000 PPMVD (UNTIL 11/00)	DRY LOW NOX COMBUSTOR (BY 11/01/00)	BACT-PSD
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI-PSD-4	4/13/02	TURBINE, GAS AND DUCT BURNER	1280.00 MMBTU/H EACH	4.0000 PPM @ 15% O2, GAS	SCR	BACT-PSD
KENTUCKY UTILITIES COMPANY	KY	C-02-005	3/10/02	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1800.00 MM BTU/HR (EACH)	42.0000 PPM @ 15% O2, N. GAS	WATER INJECTION	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	3/3/02	TURBINE, COMBUSTION	1176.00 MMBTU/H NAT. GAS	9.0000 PPM @ 15% O2	SCR, STEAM INJECTION	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	3/3/02	TURBINE, COMBUSTION	1112.00 MMBTU/H NO2 FUEL OIL	15.0000 PPM @ 15% O2	SCR, STEAM INJ.	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	3/3/02	TURBINE, COMBUSTION, 2	0.00	101.1000 T/YR/UNIT		BACT-PSD
THERMO INDUSTRIES, LTD.	CO	91WE087(1-6)	2/19/02	TURBINE, GAS FIRED, 6 EACH	248.00 MMBTU/H	25.0000 PPM @ 15% O2	DRY LOW NOX TECH	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-4629	2/12/02	TURBINES, 8	1032.00 MMBTU/H, NAT GAS	25.0000 PPM @ 15% O2	MAX WATER INJECTION	BACT-PSD
SAVANNAH ELECTRIC AND POWER CO.	GA	4911-051-4629	2/12/02	TURBINES, 8	972.00 MMBTU/H, #2 OIL	0.0000 SEE NOTES	MAX WATER INJECTION	BACT-PSD
HAWAII ELECTRIC LIGHT CO., INC.	HI	HI 90-04	2/12/02	TURBINE, FUEL OIL #2	20.00 MW	47.3000 LB/H	COMBUSTOR WATER INJECTOR WATER INJECTION	BACT-PSD
LINDEN COGENERATION TECHNOLOGY	NJ		1/21/02	TURBINE, NATURAL GAS FIRED	80.00 X E12 BTU/YR	33.0000 LB/H	STEAM INJECTION AND SCR	BACT-PSD
ALYESKA PIPELINE SERVICE COMPANY	AK	0130 AA012	1/17/02	SOLAR CENTAUR 3	800.00 KW	150.0000 PPMVD @ 15% O2	LOW NOX BURNERS	BACT-PSD
KAMINE/BESICORP NATURAL DAM LP	NY	604080 0205 00001	12/11/01	GE FRAME 6 GAS TURBINE	600.00 MMBTU/HR	42.0000 PPM, 80.1 LB/H	STEAM INJECTION	NSPS
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/01	TURBINE, COMBUSTION	1313.00 MM BTU/HR	110.0000 LB/H	MULTINOZZLE COMBUSTOR MAXIMUM WATER INJECTION	BACT
DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	NC	7171	12/20/01	TURBINE, COMBUSTION	1247.00 MM BTU/HR	207.0000 LB/H	MULTINOZZLE COMBUSTOR MAXIMUM WATER INJECTION	BACT-PSD
MAUI ELECTRIC COMPANY, LTD.	HI	HI 80-03	12/3/01	TURBINE, FUEL OIL #2	28.00 MW	42.0000 PPM	WATER INJECTION	BACT-PSD
KALAMAZOO POWER LIMITED	MI	1234-90	12/3/01	TURBINE, GAS FIRED, 2 W/ WASTE HEAT BOILERS	1806.80 MMBTU/H	15.0000 PPMV	DRY LOW NOX TURBINES	BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-178	11/20/01	TURBINE, GAS, 2 EACH	47.00 MW	75.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
LAKE COGEN LIMITED	FL	PSD-FL-178	11/20/01	TURBINE, OIL, 2 EACH	47.00 MW	42.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	PSD-FL-173	11/6/01	TURBINE, GAS, 4 EACH	36.00 MW	42.0000 PPM @ 15% O2	WET INJECTION	BACT-PSD
ORLANDO UTILITIES COMMISSION	FL	PSD-FL-173	11/6/01	TURBINE, OIL, 4 EACH	36.00 MW	65.0000 PPM @ 15% O2	WET INJECTION	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/01	TURBINE, GAS FIRED	47.84 MMBTU/H	9.0000 PPMVD @ 15% O2	HIGH TEMPERATURE SELECTIVE CATALYTIC REDUCTION	BACT-PSD
SOUTHERN CALIFORNIA GAS	CA	2046009-011	10/29/01	TURBINE, GAS FIRED, SOLAR MODEL H	5500.00 HP	9.0000 PPM @ 15% O2	HIGH TEMP SELECT. CAT. REDUCTION	BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/01	TURBINE, GAS, SOLAR CENTAUR H	5500.00 HP	64.0000 PPM @ 15% O2	LEAN BURN	BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/01	TURBINE, GAS, SOLAR CENTAUR H	6500.00 HP	42.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	NSPS
EL PASO NATURAL GAS	AZ		10/25/01	TURBINE, GAS, SOLAR CENTAUR H	6500.00 HP	85.1000 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	BACT-PSD
EL PASO NATURAL GAS	AZ		10/25/01	TURBINE, GAS, SOLAR CENTAUR H	6400.00 HP	42.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	NSPS
FLORIDA POWER GENERATION	FL	PSD-FL-187	10/18/01	TURBINE, OIL, 5 EACH	92.80 MW	42.0000 PPM @ 15% O2	WET INJECTION	BACT-PSD
EL PASO NATURAL GAS	AZ		10/18/01	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000.00 HP	226.0000 PPM @ 15% O2	LEAN BURN	BACT-PSD
EL PASO NATURAL GAS	AZ		10/18/01	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000.00 HP	42.0000 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
MUSOLT OIL CO.	CA	4131003	10/9/01	GENERATOR, STEAM, GAS FIRED	42.50 MMBTU/H	0.0430 LB/MMBTU	LOW NOX BURNER AND FLUE GAS RECIRCULATION*	BACT-PSD
EEX POWER SYSTEMS, ENCOGEN NW COGENERATION PROJECT	WA	9102	10/8/01	TURBINES, COMBINED CYCLE COGEN, GE FRAME 6	173.00 MW	3.0000 PPMDV @15% O2 NO	STEAM INJECTION AND SCR	BACT-PSD
CAROLINA POWER AND LIGHT CO.	SC	0820-0033-CA TO CC	8/28/01	TURBINES, LC	80.00 MW	202.0000 LB/H	WATER INJECTION	BACT-PSD
ENRON LOUISIANA ENERGY COMPANY	LA	PSD-LA-600	8/28/01	TURBINE, GAS, 2	38.10 MMBTU/H	40.0000 PPM @ 15% O2	H2O INJECT 0.87 LB/LB	BACT-PSD
ALGONQUIN GAS TRANSMISSION CO.	RI	1170 1177	8/6/01	TURBINE, GAS, 2	48.00 MMBTU/H	100.0000 PPM @ 15% O2	LOW NOX COMBUSTION	BACT-PSD
CHARLES LARSEN POWER PLANT	FL	PSD-FL-186	7/31/01	TURBINE, GAS, 1 EACH	80.00 MW	25.0000 PPM @ 15% O2	WET INJECTION	BACT-OTHER
CHARLES LARSEN POWER PLANT	FL	PSD-FL-186	7/26/01	TURBINE, OIL, 1 EACH	80.00 MW	42.0000 PPM @ 15% O2	WET INJECTION	BACT-PSD
SUMAS ENERGY INC.	WA		7/26/01	TURBINE, NATURAL GAS	88.00 MW	6.0000 PPM @ 15% O2	SCR	BACT-PSD
SAGUARO POWER COMPANY	NV	A393	7/24/01	COMBUSTION TURBINE GENERATOR	34.50 MW	10.0000 PPM (WINTER)	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-148	6/17/01	TURBINE, GAS, 4 EACH	400.00 MW	25.0000 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-148	6/6/01	TURBINE, OIL, 4 EACH	400.00 MW	42.0000 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-148	6/6/01	TURBINE, OIL, 2 EACH	400.00 MW	96.0000 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
GRANITE ROAD LIMITED	CA	4218001	6/6/01	TURBINE, GAS, ELECTRIC GENERATION	480.00 MMBTU/H*	3.5000 PPMVD @ 15% O2	SCR, STEAM INJECTION	BACT-PSD
NORTHERN CONSOLIDATED POWER	PA	25-028-001	5/4/01	TURBINES, GAS, 2	34.50 KW EACH	25.0000 PPM @ 15% O2	STEAM INJECTION/ + SCR IN 1997	BACT-PSD
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL; SEE NOTES	4/1/01	TURBINES (NATURAL GAS) (2)	1190.00 MMBTU/HR (EACH)	0.0320 LB/MMBTU	SCR, DRY LOW NOX BURNER	OTHER
LAKEWOOD COGENERATION, L.P.	NJ	SEVERAL; SEE NOTES	4/1/01	TURBINES (#2 FUEL OIL) (2)	1190.00 MMBTU/HR (EACH)	0.0820 LB/MMBTU	SCR AND WATER INJECTION	BACT-OTHER
CIMARRON CHEMICAL	CO	90WE438	3/25/01	TURBINE #1, GE FRAME 6	33.00 MW	25.0000 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
CIMARRON CHEMICAL	CO	90WE438	3/25/01	TURBINE #2, GE FRAME 6	33.00 MW	9.0000 PPM @ 15% O2	SCR	OTHER
SEMINOLE FERTILIZER CORPORATION	FL	PSD-FL-157	3/17/01	TURBINE, GAS	28.00 MW	9.0000 PPM @ 15% O2	SCR	OTHER
FLORIDA POWER AND LIGHT	FL	PSD-FL-165	3/16/01	TURBINE, GAS, 4 EACH	240.00 MW	47.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FLORIDA POWER AND LIGHT	FL	PSD-FL-165	3/14/01	TURBINE, OIL, 4 EACH	0.00	86.0000 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
NEVADA COGENERATION ASSOCIATES #2	NV	A391	1/17/01	COMBINED-CYCLE POWER GENERATION	85.00 MW POWER OUTPUT	81.2800 LB/H	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	BACT-PSD
NEVADA COGENERATION ASSOCIATES #1	NV	A390	1/17/01	COMBINED-CYCLE POWER GENERATION	86.00 MW TOTAL OUTPUT	81.2800 LB/H	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NJ		11/1/00	TURBINE, KEROSENE FIRED	686.00 MMBTU/HR	0.0630 LB/MMBTU	STEAM INJECTION AND SCR	BACT-PSD
NEWARK BAY COGENERATION PARTNERSHIP	NJ		11/1/00	TURBINE, NATURAL GAS FIRED	686.00 MMBTU/HR	0.0320 LB/MMBTU	STEAM INJECTION AND SCR	BACT-PSD
100 COGEN COGENERATION PLANT	NY	282400 5705 00001	8/6/00	GE LM6000 GAS TURBINE	214.00 MMBTU/HR	76.0000 PPM + NOX CORRECTION	WATER INJECTION	BACT-PSD
PEPCO - CHALK POINT PLANT	MD		6/25/00	TURBINE, 106 MW OIL FIRED ELECTRIC	106.00 MW	25.0000 PPM @ 15% O2	DRY PREMIX BURNER	BACT
PEPCO - CHALK POINT PLANT	MD		6/25/00	TURBINE, 84 MW OIL FIRED ELECTRIC	84.00 MW	65.0000 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
PEPCO - CHALK POINT PLANT	MD		6/25/00	TURBINE, 106 MW NATURAL GAS FIRED ELECTRIC	106.00 MW	77.0000 PPM @ 15% O2	DRY PREMIX AND WATER INJECTION	BACT-PSD
PEPCO - CHALK POINT PLANT	MD		6/25/00	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84.00 MW	25.0000 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
PACIFIC GAS TRANSMISSION COMPANY	OR	18-0029	6/20/00	TURBINE GAS, COMPRESSOR STATION	110.00 MMBTU/HR	109.0000 PPM @ 15% O2	LOW NOX BURNER DESIGN	BACT-PSD
PEPCO - STATION A	MD		5/21/00	TURBINE, 124 MW OIL FIRED	129.00 MW	77.0000 PPM @ 15% O2	WATER INJECTION	NSPS
PEPCO - STATION A	MD		3/21/00	TURBINE, 124 MW NATURAL GAS FIRED	125.00 MW	42.0000 PPM @ 15% O2	WATER INJECTION	BACT-PSD
PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	NJ		2/23/00	TURBINE, NATURAL GAS FIRED	1000.00 MMBTU/HR	0.0440 LB/MMBTU	STEAM INJECTION AND SCR	BACT-PSD
SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	SC	0560-0028	12/11/00	INTERNAL COMBUSTION TURBINE	110.00 MEGAWATTS	300.0000 LB/H	WATER INJECTION	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	MA	MBR-90-COM-032	11/30/00	TURBINE, 80 MW OIL FIRED	612.00 MMBTU/HR	40.0000 PPM @ 15% O2	WATER INJECTION	BACT-PSD
PEABODY MUNICIPAL LIGHT PLANT	MA	MBR-90-COM-032	11/30/00	TURBINE, 80 MW NATURAL GAS FIRED	612.00 MMBTU/HR	25.0000 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
PACIFIC GAS TRANSMISSION	OR		11/3/00	TURBINE, NAT. GAS	14800.00 HP	42.0000 PPM @ 15% O2	LOW NOX BURNERS	BACT-OTHER
SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	MD		10/1/00	TURBINE, OIL FIRED ELECTRIC	63.00 MW	100.0000 LB/H	WATER INJECTION	BACT-PSD
SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	MD		10/1/00	TURBINE, NATURAL GAS FIRED ELECTRIC	80.00 MW	189.0000 LB/H	WATER INJECTION	BACT-PSD
KINGSBURG ENERGY SYSTEMS	CA	2040230101	8/28/00	TURBINE, NATURAL GAS FIRED, DUCT BURNER	34.50 MW	8.0000 PPM @ 15% O2	SCR, STEAM INJECTION	BACT-PSD
MEGAN RACINE ASSOCIATES, INC	NY	4022010295 00001	8/6/00	GE LM6000 N COMBINED CYCLE GAS TURBINE	401.00 LB/MMBTU	42.0000 PPMDV @ 15% O2	WATER INJECTION	BACT-PSD
UNOCAL	CA	A/N 188204 AND 188295	7/16/00	TURBINE, GAS FIRED NOTE(S)	0.00	9.0000 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION (SCR) WATER INJECTN	BACT
KERN FRONT LIMITED	CA	5 1209 1 7	7/11/00	TURBINE, GAS, GENERAL ELECTRIC LM 2500	79.00 MW	94.0600 LB/D	WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION	BACT-OTHER
TOYOTA MOTOR MANUFACTURING U.S.A. INC.	KY	C-88-117	7/13/00	COMBUSTION, NATURAL GAS	0.00	0.1000 LB/MMBTU		BACT-OTHER
UNION ELECTRIC CO	MO	0679-016 TO 0679-016	6/4/99	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION TURBINE	872.00 MM BTU/HR	6242.0000 TPY	WATER INJECTION FOR NOX EMISSIONS	BACT-PSD
PILGRIM ENERGY CENTER	NY	472800 2064		(2) WESTINGHOUSE W501D5 TURBINES (EP 00001-152)	1400.00 MMBTU/HR	4.5000 PPM, 23.4 LB/H	STEAM INJECTION FOLLOWED BY SCR	BACT-PSD
LEDERLE LABORATORIES	NY	392400 0066		(2) GAS TURBINES (EP 00001-153)	110.00 MMBTU/HR	42.0000 PPM, 15 LB/H	STEAM INJECTION	BACT
BRUSH COGENERATION PARTNERSHIP	CO	91MR0341		TURBINE	350.00 MMBTU/H	25.0000 PPM @ 15% O2	DRY LOW NOX BURNER	BACT-PSD
COLORADO POWER PARTNERSHIP	CO	91MR033 1-2		TURBINE(S) 2 (NAT GAS & 2 DUCT BURNERS)	395.00 MMBTU/H EACH TURBINE	42.0000 PPM @ 15% O2	WATER INJECTION	BACT-PSD
MILAGRO, WILLIAMS FIELD SERVICE	NM	PSD-NM-658-M-4		TURBINE/COGEN, NATURAL GAS (2)	800.00 MMCF/DAY	9.0000 PPM @ 15% O2	DRY LOW NOX GENERAL ELECTRIC MODEL PG6541(B)	BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE 140 MW OIL FIRED ELECTRIC	140.00 MW	65.0000 PPM @ 15% O2	WATER INJECTION	BACT-PSD
BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	MD			TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140.00 MW	15.0000 PPM @ 15% O2	DRY BURN LOW NOX BURNERS	BACT-PSD
								BACT-PSD
DUCT FIRING								
ALABAMA POWER COMPANY - THEODORE COGENERATION	AL	503-8073	5/16/00	TURBINE WITH DUCT BURNER	170.00 MW	0.0130 LB/MMBTU	DLN COMBUSTOR IN CT, LNB IN DUCT BURNER, SCR	
LSP - COTTAGE GROVE, L.P.	MN	16300087-001	11/10/99	GENERATOR, COMBUSTION TURBINE & DUCT BURNER	1990.00 MMBTU/H (CTG)	4.5000 PPMDV @15% O2 (NG)	SELECTIVE CATALYTIC REDUCTION (SCR) WITH A NOX CEM AND A NOX PEM	BACT-PSD
GENERAL ELECTRIC PLASTICS	AL	307-0006-X016	5/27/99	COMBINED CYCLE (TURBINE AND DUCT BURNER)	0.00	0.0300 LB/MMBTU COMBINED	DRY LOW NOX BURNER ON TURBINE AND LOW NOX BURNER ON DUCT BURNER	BACT-PSD
ANDROSCOGGIN ENERGY LIMITED	ME	A-718-71-A-N	3/31/99	GAS TURBINES, COGEN, W/DUCT BURNERS	875.00 MMBTU/H TURBINE	9.0000 PPM @ 15% O2 NG	LOW NOX BURNERS, LOW NOX COMBUSTORS, SCR DURING GAS FIRING ONLY	BACT-PSD
ANDROSCOGGIN ENERGY LIMITED	ME	A-718-71-A-N	3/31/99	GAS TURBINES, COGEN, W/DUCT BURNERS	875.00 MMBTU/H TURBINE	42.0000 PPM @ 15% O2 NO OIL	LOW NOX COMBUSTORS, LOW NOX BURNERS, WATER INJECTION DURING OIL FIRING	BACT-PSD
AIR LIQUIDE AMERICA CORPORATION	LA	PSD-LA-622	2/13/98	DUCT BURNER	120.00 MMBTU/H	0.1000 LB/MMBTU	LOW NOX BURNERS	BACT-PSD
BASF CORPORATION	LA	PSD-LA-613	12/30/97	DUCT BURNER, COGEN UNIT NO. 2	0.40 MM LB/H STEAM	8.0000 PPMV NAT. GAS	LOW NOX BURNERS AND SCR TO LIMIT NOX TO 8 PPM FOR NATURAL GAS AND 25 PPM FOR WASTE GAS (80 % H2)	BACT-PSD
ALABAMA POWER COMPANY	AL	108-0010-X001 AND X002	12/17/97	COMBUSTION TURBINE W/ DUCT BURNER (COMBINED CYCLE)	100.00 MW	15.0000 PPM	DRY LOW NOX BURNERS	BACT-PSD
COLO. POWER PARTNERS, BRUSH COGEN FAC	CO	91MR053	3/27/97	COGEN TURBINE W/ DUCT BURNER & BOILERS	286.00 MM BTU/HR	42.0000 PPM @ 15% O2	LOW NOX COMBUSTION RETROFIT AND WATER INJECTION	BACT-PSD
MEAD COATED BOARD, INC.	AL	311-0004	3/12/97	DUCT BURNERS	170.00 MMBTU/HR	0.1000 LB/MMBTU (GAS)	THE PRIMARY FUEL FOR BURNER OPERATION IS NATURAL GAS. EFFICIENT BURNER OPERATION	BACT-PSD
UNION CARBIDE CORPORATION	LA	PSD-LA-580	8/22/96	DUCT BURNER	710.00 MM BTU/HR	0.1000 LB/MM BTU	LOW NOX BURNERS	BACT-PSD
KAMINE/BESICORP SYRACUSE LP	NY	313301 2010/00001 00007	12/10/94	DUCT BURNER (EP 00001)	80.00 MMBTU/HR	0.1000 LB/MMBTU	NO CONTROLS	BACT-PSD
								BACT-OTHER

Table 4-4. Summary of Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions for Combustion Turbines

Facility Name	State	Permit Number	Permit Issue Date	Unit/Process Description	Capacity Input	NO_x Emission Limit	Control Method	Basis
INDECK OSWEGO ENERGY CENTER	NY	341200 0311 00001	10/8/94	DUCT BURNER	80.00 MMBTU/HR	0.1170 LB/MMBTU 9.51 LB/HR	FUEL SPEC: NATURAL GAS ONLY	BACT-OTHER
PROJECT ORANGE ASSOCIATES	NY	311500 3015 00001	12/1/93	STACK (TURBINE AND DUCT BURNER)	715.00 MMBTU/HR	25.0000 PPM 66 LB/HR	NO CONTROLS FOR NOX ON STACK. SEE TURBINE NOX DATA	BACT-OTHER
LOCKPORT COGEN FACILITY	NY	292600 0444/00001 00003	7/14/93	(3) DUCT BURNER (EP #S 00001 00003)	84.10 MMBTU/HR	0.2000 LB/MMBTU 16.8 LB/HR	FUEL SPEC: NATURAL GAS ONLY	BACT-OTHER
ANTEC COGEN PLANT	NY	030300 0461	7/7/93	DUCT BURNER EP #00001	70.00 MMBTU/HR	0.1000 LB/MMBTU 7.0 LB/HR	2NE LOW NOX DUCT BURNER	BACT-OTHER
TIGER BAY LP	FL	PSD-FL-180	6/17/93	DUCT BURNER GAS	100.00 MMBTU/H	0.1000 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
INDECK ENERGY COMPANY	NY	603203 0000	6/12/93	DUCT BURNER EP #00001	100.00 MMBTU/HR	0.1000 LB/MMBTU, 8.6 LB/HR	FUEL SPEC: NATURAL GAS ONLY	NSPS
TRIGEN MITCHEL FIELD	NY	282089 4163 00004	4/18/93	DUCT BURNER	198.30 MMBTU/HR	0.2000 LB/MMBTU, 16.2 LB/HR	NO CONTROLS	BACT-OTHER
INTERNATIONAL PAPER CO. - RIVERDALE MILL	AL	104-0003-X026	1/11/93	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40.00 MW	0.0800 LB/MMBTU (GAS)	LOW NOX BURNERS (ON THE DUCT BURNER); STEAM INJECTION INTO THE TURBINE	BACT-PSD
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	6-2330-00016/00001-0	11/6/92	BURNER, DUCT	80.00 MMBTU/HR	0.1800 LB/MMBTU	LOW NOX BURNER	BACT-OTHER
KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	NY	6-2330-00016/00001-0	11/6/92	BURNER, DUCT	80.00 MMBTU/HR	0.1000 LB/MMBTU	LOW NOX BURNER	BACT-OTHER
KAMINE/BESICORP CORNING L.P.	NY	8-4038-00022/010	11/6/92	BURNER, DUCT	80.00 MMBTU/HR	0.1000 LB/MMBTU	LOW NOX BURNER	BACT-OTHER
BEAR ISLAND PAPER COMPANY, L.P.	VA	50840	10/20/92	BURNER, DUCT	178.00 X10(6) BTU/HR N. GAS	8.0000 PPM	SCR	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	50840	10/30/92	BURNER, DUCT	138.00 X10(6) BTU/HR #2 OIL	16.0000 PPM	SCR	BACT-PSD
BEAR ISLAND PAPER COMPANY, L.P.	VA	50840	10/30/92	BURNER, DUCT (TOTAL)	129.00 X10(6) BTU/HR	30.4000 TPY	SCR	BACT-PSD
KAMINE SOUTH GLENS FALLS COGEN CO	NY	414401 0212 00001	8/10/92	DUCT BURNER (SEE NOTE #3)	44.00 MMBTU/HR	42.0000 PPM, 57.4 LB/HR	NO CONTROLS	BACT-OTHER
SARANAC ENERGY COMPANY	NY	5-0942-00106/00001-8	7/31/92	BURNERS, DUCT (3)	553.00 MMBTU/HR EACH	0.0800 LB/MMBTU	SCR	BACT-OTHER
INDECK-YERKES ENERGY SERVICES	NY	146400 0132	6/24/92	DUCT BURNER (EP #00001)	30.00 MMBTU/HR	0.1100 LB/MMBTU 2.2 LB/HR	FUEL SPEC: NATURAL GAS ONLY	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-8	6/18/92	DUCT BURNERS (2)	208.00 MMBTU/HR EACH	0.0181 LB/MMBTU GAS	LOW NOX BURNER AND SCR	BACT-OTHER
SELKIRK COGENERATION PARTNERS, L.P.	NY	4-0122-00078/00002-8	6/18/92	DUCT BURNER	123.00 MMBTU/HR	0.0810 LB/MMBTU GAS	LOW NOX BURNER	BACT-OTHER
NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	RI	RI-PSD-4	4/12/92	TURBINE, GAS AND DUCT BURNER	1280.00 MMBTU/H EACH	9.0000 PPM @ 15% O2, GAS	SCR	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	3/3/92	BURNER, DUCT	187.00 MMBTU/H NAT. GAS	9.0000 PPMVD @ 15% O2	SCR, STEAM INJ.	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	3/3/92	BURNER, DUCT	189.00 MMBTU/H NO2 FUEL OIL	15.0000 PPMVD @ 15% O2	SCR, STEAM INJ.	BACT-PSD
BERMUDA HUNDRED ENERGY LIMITED PARTNERSHIP	VA	51020	3/3/92	BURNER, DUCT	0.00	33.3000 T/YR/UNIT		BACT-PSD
KAMINE/BESICORP NATURAL DAM LP	NY	404089 0306 00001	12/31/91	DUCT BURNER	80.00 MMBTU/HR	0.1000 LB/MMBTU, 8 LB/HR	NO CONTROLS	BACT-OTHER
LAKE COGEN LIMITED	FL	PSD-FL-178	11/20/91	DUCT BURNER, GAS	160.00 MMBTU/H	0.1000 LB/MMBTU	NOT REQUIRED	BACT-PSD
TBG COGEN COGENERATION PLANT	NY	282400 8706 00001	8/6/90	COEN DUCT BURNER	181.80 MMBTU/HR	0.2000 LB/MMBTU	FUEL SPEC: NATURAL GAS ONLY	BACT-OTHER
KINGSBURG ENERGY SYSTEMS	CA	3040230101	6/26/90	TURBINE, NATURAL GAS FIRED, DUCT BURNER	34.80 MW	5.0000 PPM @ 15% O2	SCR, STEAM INJECTION	BACT-PSD
MEGAN RACINE ASSOCIATES, INC	NY	402201 0298 00001	8/6/89	COEN DUCT BURNER	40.00 MMBTU/HR	0.1000 LB/MMBTU	FUEL SPEC: NATURAL GAS ONLY	BACT-OTHER
LEDERLE LABORATORIES	NY	393400 0006		(2) DUCT BURNERS (EP #S 00101 & 102)	96.00 MMBTU/HR	0.4000 LB/MMBTU, 36.9 LB/HR		BACT-OTHER
PILGRIM ENERGY CENTER	NY	472800 2064		(2) DUCT BURNER (EP #S 00001 & 2)	716.10 MMBTU/HR	0.0170 LB/MMBTU	FUEL SPEC: NATURAL GAS ONLY	BACT-OTHER
COLORADO POWER PARTNERSHIP	CO	91MR933-1-2		TURBINES, 2 NAT GAS & 2 DUCT BURNERS	388.00 MMBTU/H EACH TURBINE	42.0000 PPM @ 15% O2	WATER INJECTION	BACT-PSD

Source: EPA RBLC Fourth Quarter 199[illegible] Update

TABLE 4-5

CAPITAL COST FOR SELECTIVE CATALYTIC REDUCTION FOR THE SIEMENS WESTINGHOUSE 501 FD COMBINED CYCLE COMBUSTION TURBINE

Cost Component	Cost	Basis of Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	$1,578,000	Vendor Estimate
Ammonia Storage Tank	$137,529	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	Vatavauk, 1990
Instrumentation	$50,000	Additional NO_X Monitor and System
Taxes	$94,680	6% of SCR Associated Equipment and Catalyst
Freight	$78,900	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,983,614	
Direct Installation Costs		
Foundation and supports	$158,689	8% of TDCC and RCC; OAQPS Cost Control Manual
Handling & Erection	$277,706	14% of TDCC and RCC; OAQPS Cost Control Manual
Electrical	$79,345	4% of TDCC and RCC; OAQPS Cost Control Manual
Piping	$39,672	2% of TDCC and RCC; OAQPS Cost Control Manual
Insulation for ductwork	$19,836	1% of TDCC and RCC; OAQPS Cost Control Manual
Painting	$19,836	1% of TDCC and RCC; OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$615,084	
Total Capital Costs (TCC)	$2,598,699	Sum of TDCC, TDIC, and RCC
Indirect Costs		
Engineering	$259,870	10% of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$129,935	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$259,870	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$51,974	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$25,987	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$77,961	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TinCC)	$855,597	
Total Direct, Indirect and Capital Costs (TDICC)	$3,454,295	

TABLE 4-6

ANNUALIZED COST FOR SELECTIVE REDUCTION FOR THE SIEMENS WESTINGHOUSE 501 FD COMBINED CYCLE OPERATION

Cost Component	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$18,720	24 hours/week at $15/hr
Supervision	$2,808	15% of Operating Personnel; OAQPS Cost Control Manual
Ammonia	$292,815	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	Engineering Estimate
Inventory Cost	$40,004	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Cost	$364,333	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$22,010	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$755,690	
Energy Costs		
Electrical	$28,032	80 kW/h for SCR @ $0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	$334,045	0.3% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TEC)	$362,077	
Indirect Annual Costs		
Overhead	$188,606	60% of Operating/Supervision Labor
Property Taxes	$34,543	1% of Total Capital Costs
Insurance	$34,543	1% of Total Capital Costs
Annualized Total Direct Capital	$379,282	10.98% Capital Recovery Factor of 7% over 15 yrs times
Total Indirect Annual Costs (TIAC)	$636,973	
Total Annualized Costs	$1,754,741	Sum of TDAC, TEC, and TIAC
Cost Effectiveness	$2,610	NO_X Reduction Only gas and oil
	$3,267	Net Emission Reduction

Table 4-7.

Summary of Proposed BACT Control Technologies and Emission Limits

Hines Energy Complex Power Block 2

(Siemens Westinghouse 501FD CTs)

Pollutant	Fuel	Load (%)	Control Technology	Proposed BACT Emission Limits[a] Concentration (ppm)	Mass (lb/hr)
TSP/PM10	Gas	All	Natural gas and limited use of low-sulfur fuel oil	10%b	NA
	Oil	All	Efficient and complete combustion	20%b	NA
CO	Gas	100-65	Efficient and complete combustion	10	42
	Oil	100-65	Efficient and complete combustion	30	106
	Gas	60	Efficient and complete combustion	50	146
VOC	Gas	100	Efficient and complete combustion	1.8	4.4
	Oil	100-65	Efficient and complete combustion	10	21
	Gas	80-60	Efficient and complete combustion	3.0	7.5
NOx	Gas	100-60	Use of dry low-NOx burners and SCR	3.5c	23
	Oil	100-60	Water injection and SCR	15c	114
SO_2/SAM	Gas/Oil	All	Natural gas and limited use of low-sulfur fuel oil	NA	NA

a NO_x is ppmvd at 15% O_2 gas and oil; CO is ppmvd at 15% O_2 for gas and ppmvd for oil; VOC is ppmvd at 15% O_2 for gas and ppmvw for oil. Max emissions at 59°F compressor inlet.

b Percent opacity, a surrogate for TSP/PM_{10} limits.

c Based on a 24-hr block (7:00 a.m. to 7:00 a.m.) weighted average based on load as measured by CEMS.

Source: Golder Associates, 2000.

5.0 AMBIENT AIR QUALITY MONITORING DATA ANALYSIS

5.1 PSD PRECONSTRUCTION MONITORING APPLICABILITY

The maximum concentrations predicted for Power Block 2 emissions are compared to the monitoring *de minimis* levels in Table 5-1. Based on the worst-case proposed source emissions data and air quality modelling results for the proposed Power Block 2, ambient air quality monitoring is not required for SO_2, PM_{10}, NO_2, or CO because the maximum predicted impacts are less than the PSD pre-construction monitoring *de minimis* values for those pollutants (FDEP Rule 62-212.400). For ozone (O_3), annual volatile organic compound (VOC) emissions from Power Block 2 are estimated to be less than 100 tons per year. As a result, preconstruction monitoring data are also not required to be submitted as part of this application. For sulfuric acid mist, which is a noncriteria pollutant, although the proposed source's emissions are greater than the significant emission rate, EPA has established no acceptable monitoring method for this pollutant.

Therefore, FPC requests an exemption from the preconstruction monitoring for these pollutants.

TABLE 5-1

SUMMARY OF MAXIMUM MODELED POWER BLOCK 2 IMPACTS

COMPARED TO THE PSD MONITORING *DE MINIMIS* VALUES

Pollutant	Averaging Period	Highest Modeled Concentration (ug/m^3)	PSD *De Minimis* Level (ug/m^3)	Greater than the *De Minimis* Level?
Sulfur Dioxide (SO_2)	24-Hour	4.9	13	NO
Particulate Matter (PM_{10})	24-Hour	3.0	10	NO
Nitrogen Dioxide (NO_2)	Annual	0.096	14	NO
Carbon Monoxide (CO)	8-Hour	36	575	NO
Volatile Organic Compounds (VOC)	Annual	57	100 TPY	NO
Sulfuric Acid Mist	NA	NA	NA	NA

Source: Golder, 2000.

6.0 AIR QUALITY MODELLING APPROACH

This section summarizes the air quality modelling protocol and input parameters utilized in the air impact determinations presented in Section 7.0. Included are descriptions of the models, meteorology, options selected, listings of modelling parameters for the proposed facilities and existing sources, receptor locations, and step-by-step procedures that were used to develop the necessary projected impacts.

The scope of the required modelling analysis is limited to those pollutants that were determined to be subject to PSD review in Section 3.0, Table 2-5 (CO, NO_x, SO_2, PM, VOC (O_3), and sulfuric acid mist).

The proposed source emissions of sulfuric acid mist are shown in Table 2-5 to be above the PSD significant emission rates. However, the PSD regulations do not define significant impact levels nor are ambient air quality standards established for this pollutant. Hence, the air quality impact assessment for sulfuric acid mist is limited to prediction of the maximum impacts from the proposed facility.

6.1 GENERAL MODELLING APPROACH

The PSD regulations require an air quality impact assessment consisting of a proposed source significant impact area analysis, a PSD increment consumption analysis, an ambient air quality standards impact analysis, and an additional impacts analysis. These analyses are discussed in greater detail in the following sections under specific modelling methodologies. The modelling approach followed EPA and FDEP guidelines for determining compliance with applicable PSD increments and ambient air quality standards.

These results from the modeling analyses were compared to the PSD Class II and I significance levels for each pollutant in order to determine whether additional modelling was necessary. All predicted maximum concentrations were less than the PSD Class II and I significance values and *de minimis* monitoring levels.

6.2 MODEL SELECTION AND OPTIONS

6.2.1 Dispersion Model Selection

The selection of an air quality model to calculate air quality impacts for the Hines Energy Complex was based on its applicability to simulate impacts in areas surrounding the Project as well as at the PSD Class I area of the Chassahowitzka NWA, located about 118 km from the proposed source. Two air quality dispersion models were selected and used in these analyses to address air quality impacts for the proposed source. These models were:

- The Industrial Source Complex Short Term (ISCST3) dispersion model, and
- The California Puff model (CALPUFF)

The Industrial Source Complex Short-term (ISCST3, Version 99155) dispersion model (EPA, 1999) was used to evaluate the pollutant impacts due to the proposed source in nearby areas surrounding the site. This model is maintained by the EPA on its Internet website, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). The ISCST3 model is designed to calculate hourly concentrations based on hourly meteorological data (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights).

The ISCST3 model was used to provide maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. To estimate impacts due to emissions from the proposed source, an emission rate of 79.365 pounds per hour (lb/hr) or 10 grams per second (g/s) was initially used to produce relative concentrations as a function of the modeled emission rate (i.e., $\mu g/m^3$ per 10 g/s). These impacts are referred to as generic pollutant impacts. Maximum air quality impacts for specific pollutants were then determined by multiplying the maximum pollutant-specific emission rate in lb/hr (g/s) to the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s).

At distances beyond 50 km from a source, the CALPUFF model, Version 5.0 (EPA, 1998), is recommended for use by the EPA and FDEP. The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source. The methods and assumptions used in the CALPUFF model were based on the latest recommendations for modeling analysis as presented in the Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts (EPA, 1998). This model is also maintained by the EPA on the SCRAM website.

As a result, the CALPUFF model was used to perform the significant impact analysis for Power Block 2 at the Class I area of the Chassahowitzka NWA. The CALPUFF model was also used to assess the proposed source's impact on regional haze at the Class I area (see Section 8.0). Based on discussions with FDEP, the ISCST3 model was used to determine the "worst-case" operating load and ambient temperature that produced the proposed source's maximum impact at the Class I area. Based on that analysis, air quality impacts were then predicted with the CALPUFF model using the "worst-case" operating scenario to compare the source's impacts to Class I significant impact levels and potential contribution to regional haze. A more detailed description of the assumptions and methods used for the CALPUFF model is presented in Appendix B.

6.2.2 Dispersion Model Options

The area surrounding the Hines Energy Complex has been determined to be a rural area based upon the technique for urban/rural determinations documented in the EPA "Guideline on Air Quality Models", which applies land use criteria. Based upon this determination, the rural dispersion option was used in ISCST3 model.

The Regulatory Default option was used in the ISCST model for this analysis. The ISCST3 model was applied without terrain adjustment data because the area in which the Polk County Site is located has very little relief (e.g., a net change in ground level elevation in the range of only 10 feet). The ISCST3 model's building downwash options were applied because the stacks for the proposed sources will be less than the stack height at which downwash effects may occur.

In the 1992 PSD application for the Hines Energy Complex, expected emissions from both Power Block 1 and Power Block 2 were included in the dispersion modelling analysis. The analysis evaluated the total impact of the two power blocks with respect to PSD increment consumption and ambient air quality impacts. Power Block 1 has been constructed and is now operational. With approval from FDEP personnel obtained on November 23, 1998, it was determined that the analysis for proposed Power Block 2 should be updated to include use of the latest version of ISC and the most recently-approved five years of meteorological data. Therefore, this analysis re-evaluates the incremental impact of Power Block 2 on the ambient air quality surrounding the Hines Energy Complex. For purposes of model input, the two stacks for Power Block 2 were co-located; therefore, one source was input to the model.

The air quality impact assessment for PM assumed that all PM emissions were PM_{10} emissions. This assumption simplified the PM modelling analysis and makes for a conservative approach to modelling PM impacts.

Descriptions of the dispersion options for the CALPUFF model are presented in Appendix B.

6.3 METEOROLOGICAL DATA

The air quality modelling analysis used hourly preprocessed National Weather Service (NWS) surface meteorological data from Tampa, Florida, and concurrent twice-daily upper air soundings from Ruskin, Florida, for the years 1987 to 1991. The meteorological data were supplied by FDEP in the preprocessed format required by the ISCST3 model. The preprocessed hourly meteorological data file for each year of record used in the analysis contains randomized wind direction, wind speed, ambient temperature, atmospheric stability using the Turner (1970) stability classification scheme, and mixing heights. The anemometer height of 6.7 meters, used in the modelling analysis, was obtained from NWS Local Climatological Data summaries for Tampa.

These meteorological data are the most complete and representative of the region around the Project Site because both the Hines Energy Complex and the weather stations are located in areas that experience similar weather conditions, such as frontal passages. In addition, these data have been approved for use by the FDEP in previous air permit applications to address air quality impacts for other proposed sources locating in Polk County and adjacent counties.

For the CALPUFF model, additional meteorological parameters are needed (e.g., precipitation, relative humidity) to predict air quality concentrations than that required for the ISCST3 model. More detailed descriptions of the assumptions and methods used for processing the meteorological data and establishing the model domain are presented in Appendix B.

6.4 EMISSIONS INVENTORY

6.4.1 Proposed Source

The proposed combined-cycle facility will have the capability of firing natural gas and low sulfur fuel oil. The fuel scenarios evaluated for the proposed source include natural gas firing at 100%, 80%, and 60% load at 20°F, 59°F, and 90°F compressor air inlets temperature; and fuel oil firing at 100%, 80%, and 65% load at 20°F, 59°F, and 105°F compressor air inlets temperatures.

The emissions inventories for the proposed source and fuel scenarios identified above are presented in Appendix A. The pollutant emission rates shown in those tables are representative of BACT as demonstrated in Section 4.0. The air quality modelling analysis for the proposed sources assumed that maximum design capacity emissions represent actual emissions for purposes of determining PSD increment consumption.

The proposed source worst-case fuel scenario was determined by modelling each temperature and load scenario for each fuel using the ISCST3 model. The maximum impacts for the proposed source were predicted in the vicinity of the Hines Energy Complex when the source is firing fuel oil at full load at 105°F for all pollutants except CO. For CO, the maximum impacts were predicted when the source is firing natural gas at 60% load at 20°F. For PSD Class I impacts, the maximum impacts for the proposed source were predicted when the source is firing fuel oil at full load at 20°F. Complete ISCST3 model outputs have been submitted to the FDEP under separate cover.

6.4.2 Existing Sources

The results of the proposed source significant impact area analysis (which is described in Section 7.0) indicated that the proposed facility's air quality impacts are less than the PSD significant impact levels. Therefore, no additional significant impact modelling analysis for

PSD Class II increment consumption or ambient air quality standard impact is necessary.

6.5 RECEPTOR LOCATIONS

A description of the receptor grids used in this modelling analysis is presented below.

6.5.1 Receptor Grid for Proposed Source Significant Impact Analysis

This modelling analysis used a polar receptor grid beginning at 500 meters (m) and extending out to cover a 50 kilometer (km) radius centered over the proposed source. The polar grid consisted of 36 radials, each separated by 10-degree increments and extending outward at ring distances of 500 m, 1 km, and 1.5, 2.0, 2.5, 5.0, 10.0, 15.0, 20.0, 25.0, 30.0, 35.0, 40.0, 45.0, and 50.0 km with reference to the proposed source location.

In addition, receptors were placed at 100-meter intervals along the plant property boundary to assess the potential impact at the FPC property line. An additional Cartesian receptor grid with receptors placed at 100-meter intervals was input to assess concentrations near the property line closest to the source, which is to the southeast of the facility.

In total, the receptor grid which consisted of more than 700 receptors is shown in Figures 6-1 and 6-2.

The modelling results indicated no significant impacts for the PSD pollutants.

6.5.2 Receptor Grid for Class I PSD Analysis

A network of 13 discrete receptors was placed at the boundary of the Chassahowitzka NWA in order to reassess the potential incremental impact of the proposed source on that Class I area. The NWA receptors were obtained from the FDEP and were also used in the modelling analysis for the 1992 PSD application. The coordinates of these receptor points are listed in Table 6-1.

6.6 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with structures planned at the Hines Energy Complex, the 38.1 meter stacks for the proposed Power Block 2 will be less than the calculated value (61.0 meters) at which downwash effects would not be expected to occur. Therefore, the potential for building downwash was considered in the modelling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the Building Parameter Input Program (BPIP) model, which uses these parameters to create the effective wind direction-specific building dimensions for input to the model. For short stacks (i.e., physical stack height is less than $H_b + 0.5\ L_b$, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. If this method is used, then direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector.

For cases where the physical stack is greater than $H_b + 0.5\ L_b$, the Huber-Snyder (1976) method is used. In the case of the proposed CC units, the HRSG structures are the dominant buildings of influence. The dimensions of the HRSG structures are 24.4 meters high (H_b) and 13.7 meters wide (M_W). Since the proposed stack height of 38.1 meters is more than $H_b + 0.5\,L_b$, only the Huber-Snyder downwash algorithm is used by the ISCST model.

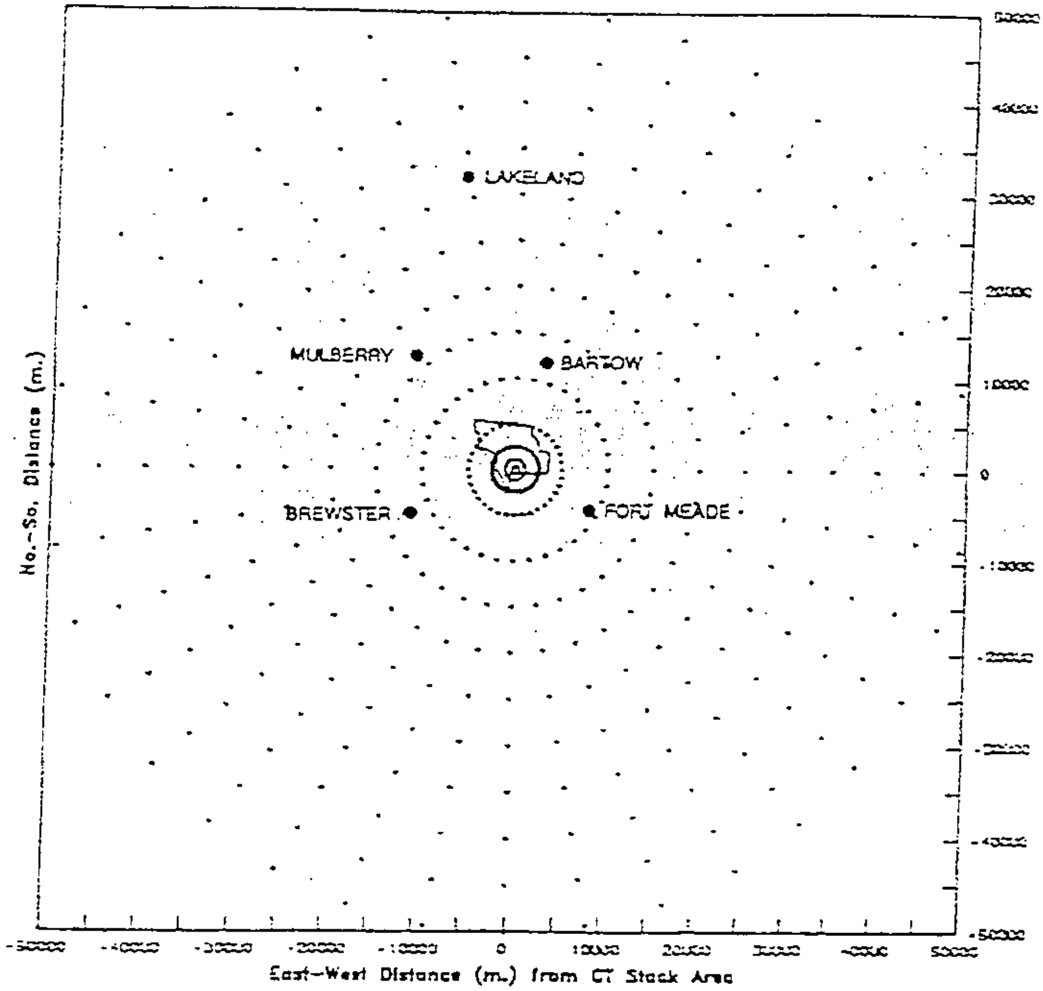
A summary of the BPIP model input and output files is provided in Appendix C.

TABLE 6-1
RECEPTOR GRID USED FOR PREDICTING CONCENTRATIONS AT THE PSD CLASS I AREA OF THE CHASSAHOWITZKA NWA

Point	UTM Coordinates		Distance from Polk County Site[a]		
	East (km)	North (km)	X (km)	Y (km)	Distance (km)
1	340.3	3,165.7	-74.0	91.82	117.9
2	340.3	3,167.7	-74.0	93.82	119.5
3	340.3	3,169.8	-74.0	95.92	121.1
4	340.7	3,171.9	-73.6	98.02	122.6
5	342.0	3,174.0	-72.3	100.12	123.5
6	343.0	3,176.2	-71.3	102.32	124.7
7	343.7	3,178.3	-70.6	104.42	126.0
8	342.4	3,180.6	-71.9	106.72	128.7
9	341.1	3,183.4	-73.2	109.52	131.7
10	339.0	3,183.4	-75.3	109.52	132.9
11	336.5	3,183.4	-77.8	109.52	134.3
12	334.0	3,183.4	-80.3	109.52	135.8
13	331.5	3,183.4	-82.8	109.52	137.3

(a) Location of "zero point" for Hines Energy Complex is 414.300 km East; 3,073.880 km North

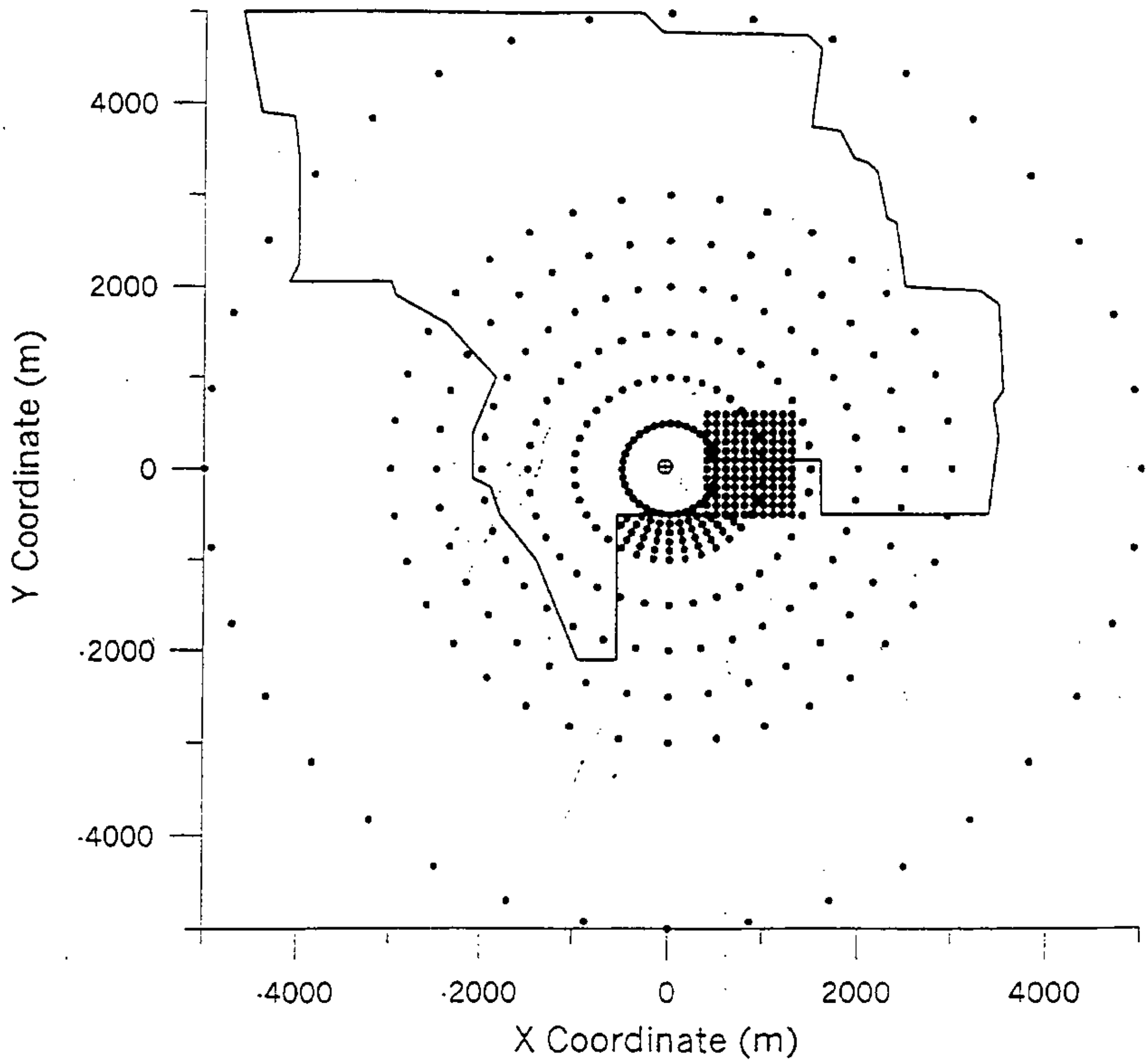
Source: FPC, 2000



Florida Power Corporation

Hines Energy Complex

FIGURE 6-1
RECEPTOR GRID FOR SIGNIFICANT IMPACT ANALYSIS



Florida Power CORPORATION

Hines Energy Complex

FIGURE 6-2
POWER BLOCK 2
RECEPTOR GRID WITHIN 5 KILOMETERS

FIGURES 6-1 and 6-2

RECEPTOR GRID FOR SIGNIFICANT IMPACT ANALYSIS

(separate document)

7.0 AIR QUALITY IMPACT ANALYSIS RESULTS

This section summarizes the results of the modelling analyses conducted as described in Section 6.0.

7.1 Power Block 2

7.1.1 Worst-case Operation Analysis

As indicated in Section 6.4.1, the proposed Power Block 2 was evaluated for both the primary fuel, natural gas, and the back-up fuel, fuel oil, to determine the worst-case impacts. Since the emissions on fuel oil are higher for the criteria pollutants than for natural gas, the analysis of short-term impacts focused on the fuel oil case. Based on the results of the ISCST3, the maximum ground-level impacts were produced for full load when firing fuel oil, except for CO emissions, which produced maximum impacts at 60% load when firing natural gas. A summary of the maximum concentrations predicted for the proposed source for the combinations of operating loads and ambient temperatures is provided in Appendix D.

Annual average concentrations were estimated by assuming that the proposed source would operate by firing fuel oil for a maximum of 1,000 hours per year and natural gas for 7,760 hours per year. The annual average concentrations were obtained by adding the maximum annual average impacts predicted for oil firing (multiplied by 1,000 hours divided by 8,760 hours) to the maximum impacts for natural gas firing (multiplied by 7,760 hours divided by 8,760 hours).

7.1.2 Significant Impact Analysis

Once the worst-case operating scenario was determined, the next step in the analysis was to determine whether the ambient air quality impact from the proposed Power Block 2 is considered significant under the PSD rules. The worst-case emissions scenario for each pollutant was modeled at the receptor locations described in Section 6.5.1.

The results of the significant impact analysis are presented in Table 7-1. As indicated in Table 7-1, there were no predicted impacts greater than the PSD significant impact levels. Thus, no further analysis is required for purposes of PSD increment consumption and AAQS compliance analysis. A complete set of the ISCST3 model output files have been submitted to the FDEP under separate cover.

7.2 PSD INCREMENT ANALYSIS

7.2.1 Class II Area

Because the maximum predicted ambient air quality impacts are less than the PSD significance levels, no additional PSD Class II increment analysis is required.

7.2.2 Class I Area

Because the proposed project will be located approximately 118 km from the nearest boundary of the nearest Class I PSD area, the Chassahowitzka NWA, the impacts of the proposed project were modelled at the Class I area. In its proposed New Source Review reform package, EPA has proposed PSD significance levels for Class I areas. FDEP has approved the use of these proposed values for purposes of assessing significant impacts at Class I areas in Florida. These values are listed in Table 7-2.

A summary of the project's maximum predicted impact on the Class I area is presented in Table 7-2. As indicated, the maximum impacts are predicted to be below the EPA significance values for PM, PM_{10}, SO_2, and NO_2. These results are based on using the CALPUFF model. Because the maximum impact of Power Block 2 emissions are predicted to be below the EPA significance values, no further analysis is required for those pollutants.

7.3 AIR TOXICS ANALYSIS

Concentrations of sulfuric acid mist were modelled with ISCST3 in the same way that SO_2 was modelled. As with SO_2, highest emissions of this pollutant occur while using fuel oil. The predicted maximum 24-hour average concentration of sulfuric acid mist is 0.75 ug/m^3. This is well below the former FDEP ambient reference concentration (ARC) of 2.4 ug/m^3. Therefore, no adverse impacts will occur from emissions of sulfuric acid mist from Power Block 2.

TABLE 7-1

SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR POWER BLOCK 2 COMPARED TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Period	Maximum Predicted Concentration (a) (ug/m^3)	Location (b) X (m)	Location (b) Y (m)	Year	Significant Impact Level (ug/m^3)	Distance to Significant Impact Level (km)	Predicted Impact Greater than the Significant Impact Level? (Yes/No)
Carbon Monoxide	1-Hour	34.9	-433	250	1988	2,000	None	No
	8-Hour	107	400	-200	1991	500	None	No
Nitrogen Dioxide	Annual	0.096	3000	0	1987	1	None	No
Sulfur Dioxide	3-Hour	17.8	400	-200	1991	25	None	No
	24-Hour	4.9	400	-200	1991	5	None	No
	Annual	0.038	3000	0	1987	1	None	No
Particulate Matter (PM_{10}) (c)	24-Hour	3.0	400	-200	1991	5	None	No
	Annual	0.039	3000	0	1987	1	None	No
Sulfuric Acid Mist	24-Hour	0.75	400	-200	1991	N/A	N/A	N/A

(a) Concentrations are highest values for this analysis; annual average concentrations based on firing natural gas and fuel oil for 7,760 and 1,000 hours, respectively.

(b) With respect to zero point of 414.30 km E; 3,073.88 km N.

(c) As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.

N/A = Not applicable

Source: Golder, 2000.

TABLE 7-2

SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR POWER BLOCK 2 COMPARED TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Period	Maximum Concentration Predicted for Power Block 2 [a] (ug/m^3)	PSD Class I Significant Impact Level (ug/m3)	Predicted Impact Greater than the PSD Significant Impact Level? (Yes/No)
Sulfur Dioxide (SO_2)	3-Hour	0.46	1.0	NO
	24-Hour	0.12	0.2	NO
	Annual	0.0014	0.1	NO
Particulate Matter (PM_{10})	24-Hour	0.033	0.3	NO
	Annual	0.0010	0.2	NO
Nitrogen Dioxide (NO_2)	Annual	0.0013	0.1	NO

[a] Concentrations are the highest values for this analysis.

Source: Golder, 2000

8.0 ADDITIONAL IMPACTS ANALYSIS

8.1 INTRODUCTION

The PSD guidelines indicate that, in addition to demonstrating that the proposed source will neither cause nor contribute to violations of the applicable PSD increments and AAQS, an additional impacts analysis must be conducted for those pollutants subject to PSD review. As indicated in Table 2-5, those pollutants include CO, NO_X, SO_2, PM, VOC (O_3), and sulfuric acid mist. This additional impacts analysis includes an analysis of air quality impacts due to growth induced by the project, an analysis of air quality impacts on soils and vegetation, and an analysis of project impacts on visibility.

As has been demonstrated in Section 7.0 of this application, the proposed project will have an insignificant impact at the NWA, located from 118 to 135 km from the proposed source. In spite of this distance, FPC is providing a general assessment of the impact of Power Block 2 on air quality-related values (AQRV) analysis as a part of this application.

8.2 IMPACTS DUE TO GROWTH

The growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the project. Only impacts related to permanent growth are considered; emissions from temporary sources and mobile sources are not addressed in the growth analysis. The analysis of socioeconomic effects presented in Chapter 7.0 of the Site Certification Application serves as the basis for this growth analysis.

Up to 500 people will be employed at the Hines Energy Complex site during any one year of the construction phase for Power Block 2, and approximately 4 new permanent jobs will be filled to operate the new facility. It is anticipated that the majority of the construction workers will commute from their current residences, whereas approximately 2 of the 4 new operational employees will migrate into the Polk County area. Based on the average household size of 2.53 persons, a total of 5 persons (workers and their families) are predicted to move into the area as a result of Power Block 2. This will have an insignificant impact on the population of Polk County.

Development of industries supporting the new CC facility are expected to be negligible. Raw materials consumed by the facility (fuels, supplies, etc.) will be delivered to the site in usable form from outside of the region. Further processing, such as water treatment, will be accomplished entirely onsite.

Electricity sales, on the other hand, will be spread out over a large region as part of FPC's generating capacity that will serve to meet increasing residential, commercial, and industrial demand throughout its system, which covers a large portion of the state of Florida.

In summary, there will be little residential growth associated with the FPC project, and there is little potential for new industrial development nearby as a result of the new facility. Impacts resulting from the new development are expected to be small and well-distributed throughout the area.

8.3 VEGETATION, SOILS, AND WILDLIFE ANALYSES

As previously discussed, the predicted maximum impacts from Power Block 2 on the NWA are less than the PSD Class I and Class II significance levels. Therefore, the project will have a negligible impact on the soils, vegetation, wildlife, and visibility of the area surrounding the plant as well as the more distant Class I area. A general discussion of air quality-related values (AQRVs) of the NWA follows.

The U.S. Department of the Interior (National Park Service) in 1978 administratively defined AQRVs to be:

All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.

Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are assets that are to be preserved if the area is to achieve the purposes for which it was set aside.

In a November 1996 report entitled "Air Quality and Air Quality Related Values in Chassahowitzka National Wildlife Refuge and Wilderness Area," the US Fish and Wildlife Service discussed vegetation, soils, wildlife, visibility, and water quality as potential AQRVs in the NWA. Effects from air pollution on visibility have been evaluated in the NWA, but the other potential AQRVs have not been specifically evaluated by the Fish and Wildlife Service for Chassahowitzka. Since specific AQRVs have not been identified for the Chassahowitzka NWA, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found on the Chassahowitzka NWA.

Vegetation type AQRVs and their representative species types have been defined as:

Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass

Marsh Islands - cabbage palm and eastern red cedar

Estuarine Habitat - black needlerush, salt marsh cordgrass, wax myrtle

Hardwood Swamp - red maple, red bay, sweet bay and cabbage palm

Upland Forests - live oak, scrub oak, longleaf pine, slash pine, wax myrtle and saw palmetto

Mangrove Swamp - red, white and black mangrove

Wildlife AQRVs included: endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles and mammals.

A screening approach was used which compared the maximum predicted ambient concentration of air pollutants of concern in the Chassahowitzka NWR with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the NWR. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens and species of the hardwood swamplands and mangrove forest, no specific citations that addressed these species were found. It was recognized that effect threshold information is not available for all species found in the Chassahowitzka NWR, although studies have been performed on a few of the common species and on other similar species which can be used as models. Maximum concentrations were predicted using the CALPUFF model as described in Sections 6.0 and 7.0.

8.3.1 Vegetation

The effects of air contaminants on vegetation occur primarily from sulfur dioxide, nitrogen dioxide, ozone, and particulates. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, carbon monoxide, and pesticides have been reported in the literature. However, most of these air contaminants have not resulted in major effects (i.e., crop damage). Some air contaminants, such as ethylene, are widely distributed but, due to low concentrations, do not result in injury to plants. Others such as CO do not cause damage at concentrations normally found under ambient concentrations. There are no predicted fluoride emissions from the proposed project.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms, while chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant.

Since predicted maximum pollutant concentrations at the NWA are below significance levels, no adverse effects to vegetation will be caused by the proposed project.

8.3.2 Soils

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter or particulate matter to which certain contaminants are absorbed. Gaseous fumigation of soils does not directly affect the soil but rather the organisms found in the soil. Concentrations several orders of magnitude higher than the predicted values are required before any adverse effects from fumigation are observed. It is more likely that effects on soils and the organisms (plants and animals) found in the soils could occur from the deposition of trace elements over the life of the project. Thus, this analysis of effects on soils specifically addresses the deposition of trace elements and potential pathways for movements into the vegetation.

8.3.2.1 Lead

Lead (Pb) is found naturally occurring in all plants, although it is nonessential for growth (Chapman, 1966; Valkovic, 1975; Gough and Shacklette, 1976). Plants vary in their sensitivity to lead. Many plants tolerate high concentrations of lead, while others exhibit retarded growth at 10 ppm in solution culture (Valkovic, 1975). Orange seedlings grown on soils with lead concentrations ranging from 150-200 ppm did not exhibit adverse effects (Chapman, 1966). Gough et al. (1979) reported that a lead soil concentration of 30 to 100 g/g generally retarded the growth of plants. The negligible amount of lead emissions from Power Block 2 will not contribute to a soil concentration toxic to plants.

8.3.2.2 Mercury

Mercury (Hg) is not an essential element for plant growth. It is typically used as a seed fungicide. In general, Hg is not concentrated in plants grown on soils containing normal levels of Hg. Soil bound Hg is typically not available for plant uptake, although many plants cannot prevent the uptake of gaseous Hg through the roots (Huckabee and

Jansen, 1975). Most higher vascular plants are resistant to toxicity from high Hg concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm ($HgCl_2$) were found to inhibit the growth of cauliflower, lettuce, potato, and carrots (Bell and Rickard, 1974). Gough et al. (1979) noted apparently healthy Spanish moss plants with a mercury content of 0.5 mg/kg. The extremely small amount of mercury emissions from the proposed power block will not contribute to concentrations toxic to plants.

8.3.3 Wildlife

Compared with other threats to wildlife, such as pesticides, the toxicological relationships between air pollution and effects on wildlife are not well understood (Newman and Schreiber, 1988). The limited understanding is based primarily on reports of symptoms observed in the field and on information extrapolated from laboratory studies. Information on controlled wildlife studies is limited in the scientific literature. Most studies report symptoms of various air pollutants but do not provide toxicity levels. Those studies that do provide toxicity levels are limited to four air contaminants, SO_2, NO_2, O_3, and particulates.

Since the predicted maximum pollutant impacts are less than Class I significance levels, no adverse impacts to wildlife will occur from the proposed Power Block 2 emissions.

In addition to the impacts on wildlife from the primary pollutants, the Fish and Wildlife Service is concerned about the effects on wildlife resulting from acid deposition (FWS, 1992). Existing acid deposition conditions in Florida were investigated during the five year Florida Acid Deposition Study (ESE, 1986 and 1987) and the two year follow-up program called the Florida Acid Deposition Monitoring Program (ESE, 1988 and 1989). The data collected in these programs indicate that Florida precipitation is only about two-thirds as acidic as precipitation across the southeastern United States and less than half as acidic as precipitation in the midwestern and northeastern United States (ESE, 1988). There is no evidence of a temporal trend in precipitation acidity since the late 1970s (ESE, 1989).

The Clean Air Act Amendments of 1990 require significant reductions in SO_2 and NO_2 emissions from existing uncontrolled utility plants nationwide and some of these reductions will occur at plants in the general vicinity of the NWA. These emission reductions will undoubtedly improve on the already good estimated acid deposition conditions in the NWR.

Due to the small emission increases that will be caused by the proposed project and the resulting insignificant concentrations, increase, if any in acid deposition will be negligible.

8.4 IMPACTS UPON VISIBILITY

8.4.1 General

Visibility is an AQRV for the Chassahowitzka NWA. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the Chassahowitzka NWA lies more than 50 km from the Hines Energy Complex, the change in visibility is analyzed as regional haze. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where: b_{exts} is the extinction coefficient calculated for the source, and

b_{extb} is the background extinction coefficient

A similar index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

8.4.2 IWAQM Recommendations

The CALPUFF air modeling analysis followed the recommendations contained in the IWAQM Phase 2 Summary Report (EPA, 1998). A detailed description of the methods and assumptions used in this is presented in Appendix B. Air quality impacts for the refined analyses were calculated as follows:

1. Obtain maximum 24-hour sulfate (SO_4) and nitrate (NO_3) impacts, in units of micrograms per cubic meter ($\mu g/m^3$).

2. Convert the SO_4 impact to ammonium sulfate $(NH_4)_2SO_4$ by the following formula:

$$(NH_4)_2SO_4\ (\mu g/m^3) = SO_4\ (\mu g/m^3) \times \text{molecular weight } (NH_4)_2SO_4 \,/\, \text{molecular weight } SO_4$$

$$(NH_4)_2SO_4\ (\mu g/m^3) = SO_4\ (\mu g/m^3) \times 132/96$$

$$= SO_4\ (\mu g/m^3) \times 1.375$$

3. Convert the NO_3 impact to ammonium nitrate (NH_4NO_3) by the following formula:

$$NH_4NO_3\ (\mu g/m3) = NO3\ (\mu g/m^3) \times \text{molecular weight } NH_4NO_3 \,/\text{molecular weight } NO_3$$

$$NH_4NO_3\ (\mu g/m^3) = NO_3\ (\mu g/m^3) \times 80/62$$

$$= NO_3\ (\mu g/m^3) \times 1.29$$

4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

$$b_{exts} = 3 \times NH_4NO_3 \times f(RH) + 3 \times (NH_4)_2SO_4 \times f(RH) + 3 \times PM_{10}$$

5. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLM with the following formula:

$$b_{extb} = 3.912 / \text{Visual range (km)}$$

6. Compute the change in extinction coefficients:

In terms of deciviews:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

In terms of percent change of visibility:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

Based on the predicted SO_4, NO_3, and PM_{10} concentrations, the Power Block 2's emissions are compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

8.4.3 Background Visual Ranges And Relative Humidity Factors

The background visual range is based on data representative of the top 20-percentile of visual range data measured at Chassahowitzka NWA. The background visual range for the Chassahowitzka NWA is 65 km and was provided by the FLM. The average relative humidity factor for each day during which the highest concentrations were predicted was computed by averaging the hourly relative humidity factor based on the hourly relative humidity for the 24-hour period. This factor was estimated by using data presented in the Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Draft Phase I Report (October 1999).

8.4.4 Regional Haze Analysis

The results of the Phase 2 refined analysis for regional haze are summarized in Tables 8-1 through 8-3. As shown in Table 8-1, the maximum pollutant impacts were predicted to occur on August 16, 1990 (Julian Day 228) for SO_4, July 4, 1990 (Julian

Day 185) for NO_3, and November 28, 1990 (Julian Day 332) for PM_{10}. The calculated average relative humidity factors for these days are presented in Table 8-2. The maximum changes in visibility due to the Project for these days are summarized in Table 8-3. As shown in Table 8-3, the maximum change in visibility on November 28 is estimated to be 3.19 percent or 0.319 deciviews. This impact is below the FLM's screening criteria of 5 percent or 0.5 deciview change. As a result, this indicates that the Power Block 2's emissions would not have an adverse impact on the existing regional haze at the PSD Class I area of the Chassahowitzka NWA.

TABLE 8-1

MAXIMUM POLLUTANT CONCENTRATIONS PREDICTED FOR POWER BLOCK 2, HINES ENERGY COMPLEX AT THE CHASSAHOWITZKA PSD CLASS I AREA

Pollutant	Maximum Predicted Concentrations[a] ($\mu g/m^3$)		
	July 4 (185)	August 16 (228)	November 28 (332)
SO_4	0.0190	0.395[b]	0.0157
NO_3	0.0383[b]	0.0134	0.0285
PM_{10}	0.0988	0.0926	0.124[b]

[a] Predicted with CALPUFF model in the refined mode (Julian Day in parentheses)

[b] Highest concentration predicted for specific pollutant. Maximum concentrations for SQ, NO_3, and PM_{10} predicted for 100% load at 20°F.

Source: Golder, 2000

TABLE 8-2
COMPUTED DAILY AVERAGE RH FACTORS FOR DAYS OF MAXIMUM IMPACTS PREDICTED FOR POWER BLOCK 2, HINES ENERGY COMPLEX, AT THE PSD CLASS I AREA OF THE CHASSAHOWITZKA NWA

HOUR	July 4 (185)[a]		August 16 (228)[a]		November (332)[a]	
ENDING	RH(%)	f(RH)	RH(%)	f(RH)	RH(%)	f(RH)
0	90	4.7	87	3.8	97	15.1
1	82	3.0	90	4.7	97	15.1
2	85	3.4	94	8.4	97	15.1
3	87	3.	94	8.4	100	21.4
4	90	4.7	94	8.4	97	15.1
5	87	3.8	94	8.4	100	21.4
6	93	7.0	94	8.4	97	15.1
7	85	3.4	88	4.0	100	21.4
8	74	2.1	82	3.0	97	15.1
9	69	1.9	77	2.4	91	5.3
10	67	1.7	68	1.8	82	3.0
11	61	1.5	59	1.4	77	2.4
12	55	1.3	52	1.3	69	1.9
13	52	1.3	52	1.3	69	1.9
14	42	1.1	49	1.2	67	1.7
15	46	1.2	49	1.2	65	1.7
16	52	1.3	47	1.2	67	1.7
17	61	1.5	50	1.2	74	2.1
18	67	1.7	74	2.1	82	3.0
19	72	2.0	82	3.0	87	3.8
20	72	2.0	74	2.1	90	4.7
21	74	2.1	77	2.4	90	4.7
22	79	2.6	85	3.4	94	8.4
23	82	3.0	85	3.4	97	15.1
Average		2.59		3.62		9.01

Note: RH = relative humidity; f(RH) = relative humidity factor

[a] Hourly relative humidity data for 1990 from the National Weather Service station at the Tampa International Airport in Tampa, Florida. Julian day in parenthesis.

Source: Golder, 2000

TABLE 8-3
SUMMARY OF THE REFINED REGIONAL HAZE ANALYSES FOR POWER BLOCK 2'S IMPACTS PREDICTED AT THE PSD CLASS I AREA OF THE CHASSAHOWITZKA NWA

Parameter	Units	Days of Maximum Concentrations Predicted for the Project		
		July 4 (185)	August 16 (228)	November 28 (332)
Maximum Predicted Concentration	μg/m³			
SO_4		0.0190	0.0395	0.0157
NO_3		0.0383	0.0134	0.0285
PM_{10}		0.0988	0.0926	0.124
Computer Concentrations	μg/m³			
$(NH_4)_2SO_4$		0.0262	0.0543	0.0216
NH_4NO_3		0.0494	0.0173	0.0367
Average Relative Humidity Factor [a]		2.59	3.62	9.01
Background Visual Range (Vr) [b]		65	65	65
Background Extinction Coefficient (b_{ext})	km^{-1}	0.0602	0.0602	0.0602
Source Extinction Coefficients (bexts)	km^{-1}			
$(NH_4)_2SO_4$		0.000203	0.000590	0.000584
NH_4NO_3		0.000384	0.000188	0.000992
PM_{10}		0.000297	0.000278	0.000372
Total bexts		0.000883	0.001056	0.001948
Deciview Change		0.146	0.174	0.319
Percent Change (%)		1.46	1.74	3.19
Allowable Criteria (%)		5.0	5.0	5.0

[a] Computed from relative humidity data measured in 1990 at the National Weather Service station at the Tampa International Airport, Florida

[b] Provided by U.S. Fish and Wildlife Service

Source: Golder, 2000

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APPENDIX A

Table A-1. Design Information and Stack Parameters for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 100 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	72°F	90°F
Combustion Turbine Performance				
Evaporative cooler status/ efficiency (%)	Off	Off	Off	Off
Ambient Relative Humidity (%)	60	60	60	55
Gross power output (MW) - Estimated	200.88	181.74	174.22	157.91
Gross heat rate (Btu/kWh, LHV) - Estimated	8,835	9,100	9,180	9,510
(Btu/kWh, HHV)	9,915	10,085	10,195	10,550
Heat Input (MMBtu/hr, LHV)- calculated	1,775	1,654	1,599	1,502
- provided	1,813	1,649	1,596	1,537
(MMBtu/hr, HHV) - calculated	2,012	1,830	1,771	1,705
(HHV/LHV)	1.110	1.110	1.110	1.110
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039	21,039
(Btu/lb, HHV)	23,345	23,345	23,345	23,345
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)	3,885,997	3,624,720	3,504,549	3,353,000
Temperature (°F)	1,086	1,107	1,118	1,148
Moisture (% Vol.)	7.77	8.39	9.45	11.64
Oxygen (% Vol.)	12.52	12.53	12.32	11.99
Molecular Weight - calculated	28.46	28.39	28.27	28.04
- provided	28.46	28.39	28.27	28.03
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,885,997	3,624,720	3,504,549	3,353,000
Temperature (°F)	1,086	1,107	1,118	1,148
Molecular weight	28.46	28.39	28.27	28.04
Volume flow (acfm)- calculated	2,567,660	2,433,641	2,379,291	2,339,045
- provided				
Fuel Usage				
Fuel usage (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,813	1,649	1,596	1,537
Heat content (Btu/lb, LHV)	21,039	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	86,180	78,380	75,850	73,050
- provided	86,180	78,380	75,850	73,050
Heat content (Btu/cf, LHV)- assumed	920	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,970,805	1,792,431	1,734,574	1,670,542
Stack and Exit Gas Conditions- HRSG				
Stack height (ft)	125	125	125	125
Diameter (ft)	19.0	19.0	19.0	19.0
Temperature (°F)	190	190	190	190
HRSG- Volume flow (acfm)= CT Volume flow (acfm) x [(HRSG Temp. (°F) + 460 K) / (CT Temp. (°F) + 460)]				
CT Volume flow (acfm)	2,567,660	2,433,641	2,379,291	2,339,045
CT Temperature (°F)	1,086	1,107	1,118	1,148
HRSG Temperature (°F)	190	190	190	190
HRSG Volume flow (acfm)	1,079,547	1,009,487	980,063	945,509
Velocity (ft/sec)= Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min				
Volume flow (acfm)	1,079,547	1,009,487	980,063	945,509
Diameter (ft)	19.0	19.0	19.0	19.0
Velocity (ft/sec)- calculated	63.3	59.2	57.4	55.4

Source: Siemens-Westinghouse, 2000

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2

Table A-2. Maximum Emissions for Criteria and Other Regulated Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Natural Gas, 100 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	72°F	90°F
Hours of Operation	8,760	8,760	8,760	8,760
Particulate from CT and SCR				
Particulate from CT = Emission rate (lb/hr) from CT manufacturer (front- and back-half)				
Basis, lb/hr - provided [a]	7.3	6.8	6.5	6.2
Particulate from SCR = Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (= PM10)				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	5.6	5.1	5.0	4.8
Conversion (%) from SO_2 to SO_3	10	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
Particulate (lb/hr)- calculated	1.16	1.06	1.02	0.98
Particulate (lb/hr) from CT + SCR	8.5	7.9	7.5	7.2
(TPY)	37.1	34.4	32.9	31.5
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel use (cf/hr)	1,970,805	1,792,431	1,734,374	1,670,542
Sulfur content (grains/ 100 cf) - assumed [b]	1	1	1	1
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)- calculated	5.6	5.1	5.0	4.8
(lb/hr)- provided (1 gr/100 cf)	5.5	5.1	5.0	4.7
(TPY)	24.7	22.4	21.7	20.9
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2 [a,d]	3.5	3.5	3.5	3.5
Moisture (%)	7.77	8.39	9.45	11.64
Oxygen (%) +	12.52	12.53	12.32	11.99
Volume Flow (acfm)	2,567,660	2,433,641	2,379,291	2,339,045
Temperature (°F)	1,086	1,107	1,118	1,148
Emission rate (lb/hr)- calculated	25.2	23.1	22.3	21.1
(lb/hr)- provided	25.0	23.1	22.3	21.2
(TPY)	109.5	101.2	97.7	92.9
[Ratio lb/hr provided/calculated]	0.993	1.002	0.998	1.003
Carbon Monoxide (lb/hr) = CO(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd - calculated	12.4	12.2	12.4	12.4
Basis, ppmvd @ 15% O2- calculated	10	10	10	10
- provided [a]	10	10	10	10
Moisture (%)	7.77	8.39	9.45	11.64
Oxygen (%)	12.52	12.53	12.32	11.99
Volume Flow (acfm)	2,567,660	2,433,641	2,379,291	2,339,045
Temperature (°F)	1,086	1,107	1,118	1,148
Emission rate (lb/hr)- calculated from given ppmvd	43.8	40.1	38.9	36.8
(lb/hr)- provided	46.0	42.0	41.0	37.0
(TPY)	201.5	184.0	179.6	162.1
[Ratio lb/hr provided/calculated]	1.051	1.048	1.055	1.007
VOCs (lb/hr) = VOC(ppm) x [1 - Moisture(%)/ 100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd (as CH_4)- calculated	#NAME?	#NAME?	#NAME?	#NAME?
Basis, ppmvd @ 15% O_2- calculated	#NAME?	#NAME?	#NAME?	#NAME?
- provided [a,e]	#NAME?	#NAME?	#NAME?	#NAME?
Moisture (%)	7.77	8.39	9.45	11.64
Oxygen (%)	12.52	12.53	12.32	11.99
Volume Flow (acfm)	2,567,660	2,433,641	2,379,291	2,339,045
Temperature (°F)	1,086	1,107	1,118	1,148
Emission rate (lb/hr)- calculated	#NAME?	#NAME?	#NAME?	#NAME?
(lb/hr)- provided	#NAME?	#NAME?	#NAME?	#NAME?
(TPY)	#NAME?	#NAME?	#NAME?	#NAME?
[Ratio lb/hr provided/calculated]	#NAME?	#NAME?	#NAME?	#NAME?
Lead (lb/hr) = NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA
(TPY)	NA	NA	NA	NA
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr), HHV- CT	2,012	1,830	1,771	1,705
- Duct Burner	0	0	0	0
Total	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	1.61E-06	1.46E-06	1.42E-06	1.36E-06
(TPY)	7.05E-06	6.41E-06	6.20E-06	5.96E-06
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)				
SO_2 emission rate (lb/hr)	5.6	5.1	5.0	4.8
lb H_2SO_4 /lb SO_2 (98/64)	1.53	1.53	1.53	1.53
Conversion to H_2SO_4 (%) (b)	10	10	10	10
Emission Rate (lb/hr)	0.86	0.78	0.76	0.73
(TPY)	3.78	3.43	3.32	3.20

Source: [a] Siemens-Westinghouse, 2000.
[b] Golder Associates Inc. 1999.
[c] Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
[d] For NO_x emissions, data originally provided at 25 ppmvd at 15% oxygen.
[e] For VOC emissions, data originally provided at 1.5 ppmvd at 15% oxygen.

Note: ppmvd = parts per million, volume dry; O_2 = oxygen.

Table A-3. Maximum Emissions for Other Regulated PSD Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 100 % Load

Parameter		Ambient/Compressor Inlet Temperature		
	20 °F	59 °F	72°F	90°F
Hours of Operation	8,760	8,760	8,760	0
Heat Input Rate (MMBtu/hr), HHV- CT	2,012	1,830	1,771	1,705
Duct burner	0	0	0	0
Total	2,012	1,830	1,771	1,705
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	2.41E-09	2.20E-09	2.12E-09	2.05E-09
(TPY)	1.06E-08	9.62E-09	9.31E-09	0.00E+00
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	2,012	1,830	1,771	1,705
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-4. Maximum Emissions for Hazardous Air Pollutants for the FPC Hines Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Natural Gas, 100 % Load

Parameter		20 °F	59 °F	72°F	90°F
		Ambient/Compressor Inlet Temperature			
Hours of Operation		8,760	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT		2,012	1,830	1,771	1,705
	Duct burner	0	0	0	0
	Total	2,012	1,830	1,771	1,705
Antimony (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		8.00E-01	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		1.61E-03	1.46E-03	1.42E-03	1.36E-03
(TPY)		7.05E-03	6.41E-03	6.20E-03	5.98E-03
Cadmium (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Formaldehyde (lb/hr) = 10% of VOC lb/hr					
Emission Rate, lb/10[12] Btu		#NAME?	#NAME?	#NAME?	#NAME?
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		#NAME?	#NAME?	#NAME?	#NAME?
(TPY)		#NAME?	#NAME?	#NAME?	#NAME?
Cobalt (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Selenium (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
(TPY)		0.00E+00	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10[12] Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10[12] Btu					
Basis, lb/10[12] Btu		1.00E+01	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)		2,012	1,830	1,771	1,705
Emission Rate (lb/hr)		2.01E-02	1.83E-02	1.77E-02	1.71E-02
(TPY)		8.81E-02	8.01E-02	7.76E-02	7.47E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-5. Design Information and Stack Parameters for the FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Natural Gas, 80 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	90 °F
Combustion Turbine Performance			
Evaporative cooler status/ efficiency (%)	Off	Off	Off
Ambient Relative Humidity (%)	60	60	55
Gross power output (MW) - Estimated	160.80	145.19	127.40
Gross heat rate (Btu/kWh, LHV) - Estimated	9,255	9,516	10,065
(Btu/kWh, HHV)	10,270	10,555	11,170
Heat Input (MMBtu/hr, LHV)- calculated	1,488	1,382	1,282
- provided	1,385	1,382	1,279
(MMBtu/hr, HHV) - calculated	1,537	1,534	1,419
(HHV/LHV)	1.110	1.110	1.110
Fuel heating value (Btu/lb, LHV)	21,039	21,039	21,039
(Btu/lb, HHV)	23,345	23,345	23,345
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)	3,497,411	3,302,475	3,118,517
Temperature (°F)	1,006	1,032	1,083
Moisture (% Vol.)	7.10	7.75	9.14
Oxygen (% Vol.)	13.27	13.25	13.12
Molecular Weight - calculated	28.50	28.43	28.27
- provided	28.51	28.43	28.27
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	3,497,411	3,302,475	3,118,517
Temperature (°F)	1,006	1,032	1,083
Molecular weight	28.50	28.43	28.27
Volume flow (acfm)- calculated	2,188,271	2,108,318	2,070,770
Fuel Usage			
Fuel usage (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,385	1,382	1,279
Heat content (Btu/lb, LHV)	21,039	21,039	21,039
Fuel usage (lb/hr)- calculated	65,830	65,710	60,790
- provided	65,830	65,710	60,790
Heat content (Btu/cf, LHV)	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,505,432	1,502,688	1,390,175
Stack and Exit Gas Conditions- HRSG			
Stack height (ft)	125	125	125
Diameter (ft)	19.0	19.0	19.0
Temperature (°F)	190	190	190
HRSG- Volume flow (acfm)= CT Volume flow (acfm) x [(HRSG Temp. (°F) + 460 K) / (CT Temp. (°F) + 460)]			
CT Volume flow (acfm)	2,188,271	2,108,318	2,070,770
CT Temperature (°F)	1,006	1,032	1,083
HRSG Temperature (°F)	190	190	190
HRSG Volume flow (acfm)	970,243	918,503	872,327
Velocity (ft/sec)= Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Volume flow (acfm)	970,243	918,503	872,327
Diameter (ft)	19.0	19.0	19.0
Velocity (ft/sec)- calculated	57.0	54.0	51.3

Source: Siemens-Westinghouse, 2000.

Note: Universal gas constant= 1,545 ft-lb(force)/°R; atmospheric pressure= 2,116.8 lb(force)/ft^2.

Table A-6. Maximum Emissions for Criteria and Other Regulated Pollutants for the FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Natural Gas, 80 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	90 °F
Hours of Operation	8,760	8,760	8,760
Particulate from CT and SCR			
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer (front- and back-half)			
Base, lb/hr - provided [a]	6.6	6.2	5.5
Particulate from SCR = Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/lb SO_3			
SO_2 emission rate (lb/hr)- calculated	4.3	4.3	4.0
Conversion (%) from SO_2 to SO_3	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7
Particulate (lb/hr)- calculated	0.89	0.89	0.82
Particulate (lb/hr) from CT + SCR	7.5	7.1	6.3
(TPY)	32.8	31.0	27.7
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2/lb S) /100			
Fuel use (cf/hr)	1,505,432	1,502,688	1,390,175
Sulfur content (grains/ 100 cf) - assumed [b]	1	1	1
lb SO_2/lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	4.3	4.3	4.0
(lb/hr)- provided (1 gr/100 cf)	4.60	4.30	3.80
(TPY)	18.8	18.8	17.4
Nitrogen Oxides (lb/hr) = NO_x(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NO_x) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2 [a,d]	3.5	3.5	3.5
Moisture (%)	7.10	7.75	9.14
Oxygen (%)	13.27	13.25	13.12
Volume Flow (acfm)	2,188,271	2,108,318	2,070,770
Temperature (°F)	1,006	1,032	1,083
Emission rate (lb/hr)- calculated	20.6	19.1	17.7
(lb/hr)- provided	20.6	19.1	17.7
(TPY)	90.2	83.7	77.5
[Ratio lb/hr provided/calculated]	1.001	0.999	1.002
Carbon Monoxide (lb/hr) = CO(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd- calculated	11.2	11.1	10.9
Basis, ppmvd @ 15% O_2- calculated	10	10	10
- provided [a]	10	10	10
Moisture (%)	7.10	7.75	9.14
Oxygen (%)	13.27	13.25	13.12
Volume Flow (acfm)	2,188,271	2,108,318	2,070,770
Temperature (°F)	1,006	1,032	1,083
Emission rate (lb/hr)- calculated from given pp	35.8	33.2	30.7
(lb/hr)- provided	38.0	35.0	33.0
(TPY)	166.4	153.3	144.5
[Ratio lb/hr provided/calculated]	1.062	1.053	1.074
VOCs (lb/hr) = VOC(ppm) x [1 - Moisture(%)/ 100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd (as CH_4)- calculated	#NAME?	#NAME?	#NAME?
Basis, ppmvd @ 15% O_2 - calculated	#NAME?	#NAME?	#NAME?
- provided [a,e]	#NAME?	#NAME?	#NAME?
Moisture (%)	7.10	7.75	9.14
Oxygen (%)	13.27	13.25	13.12
Volume Flow (acfm)	2,188,271	2,108,318	2,070,770
Temperature (°F)	1,006	1,032	1,083
Emission rate (lb/hr)- calculated	#NAME?	#NAME?	#NAME?
(lb/hr)- provided	#NAME?	#NAME?	4.2
(TPY)	#NAME?	#NAME?	18.4
[Ratio lb/hr provided/calculated]	#NAME?	#NAME?	#NAME?
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA
(TPY)	NA	NA	NA
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	1.23E-06	1.23E-06	1.14E-06
(TPY)	5.38E-06	5.38E-06	4.97E-06
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4/MW SO_2 (98/64)			
SO_2 emission rate (lb/hr)	4.3	4.3	4.0
lb H_2SO_4/lb SO_2 (98/64)	1.53	1.53	1.53
Conversion to H_2SO_4 (%) [b]	10	10	10
Emission Rate (lb/hr)	0.66	0.66	0.61
(TPY)	2.88	2.88	2.66

Source: [a] Siemens-Westinghouse, 2000.
[b] Golder Associates Inc. 2000.
[c] Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
[d] For NO_x emissions, data originally provided at 25 ppmvd at 15% oxygen.
[e] For VOC emissions, data originally provided at 2.8 ppmvd at 15% oxygen.

Table A-7. Maximum Emissions for Other Regulated PSD Pollutants for the FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Natural Gas, 80 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	90 °F
Hours of Operation	8,760	8,760	8,760
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	1.84E-09	1.84E-09	1.70E-09
(TPY)	8.08E-09	8.06E-09	7.46E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0	0
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0	0
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Note: No emission factors for hydrogen chloride (HCl) from natural gas-firing.

Table A-8. Maximum Emissions for Hazardous Air Pollutants for the FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Natural Gas, 80 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	90 °F
Hours of Operation	8,760	8,760	8,760
Antimony (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	1.23E-03	1.23E-03	1.14E-03
(TPY)	5.38E-03	5.38E-03	4.97E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Formaldehyde (lb/hr) = 10% of VOC lb/hr			
Emission Rate, lb/10^{12} Btu	#NAME?	#NAME?	#NAME?
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	#NAME?	#NAME?	#NAME?
(TPY)	#NAME?	#NAME?	#NAME?
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,537	1,534	1,419
Emission Rate (lb/hr)	1.54E-02	1.53E-02	1.42E-02
(TPY)	6.73E-02	6.72E-02	6.22E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-9. Design Information and Stack Parameters for the FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 65 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	105 °F
Combustion Turbine Performance			
Evaporative cooler status/ efficiency (%)	Off	Off	Off
Ambient Relative Humidity (%)	80	80	60
Gross power output (MW)	130.28	117.71	98.49
Gross heat rate (Btu/kWh, LHV)	9,865	10,250	10,820
(Btu/kWh, HHV)	10,840	11,370	12,005
Heat Input (MMBtu/hr, LHV)- calculated	1,285	1,207	1,066
- provided	1,284	1,206	1,076
(MMBtu/hr, HHV) - provided	1,425	1,336	1,184
(HHV/LHV)	1.110	1.108	1.100
Fuel heating value (Btu/lb, LHV)	21,038	21,038	21,038
(Btu/lb, HHV)	23,345	23,345	23,345
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)	3,008,355	2,857,150	2,653,681
Temperature (°F)	1,051	1,087	1,089
Moisture (% Vol.)	7.17	7.84	10.90
Oxygen (% Vol.)	13.19	13.14	12.83
Molecular Weight - calculated	28.51	28.42	28.07
- provided	28.50	28.42	28.07
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F) + 460°F)] / [Molecular weight x 2116.8] / 60 min/hr			
Mass flow (lb/hr)	3,008,355	2,857,150	2,653,681
Temperature (°F)	1,051	1,087	1,089
Molecular weight	28.51	28.42	28.07
Volume flow (acfm)- calculated	1,939,295	1,891,657	1,781,152
- provided			
Fuel Usage			
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))			
Heat input (MMBtu/hr, LHV)	1,284	1,206	1,076
Heat content (Btu/lb, LHV)	21,038	21,038	21,038
Fuel usage (lb/hr)- calculated	61,032	57,325	51,146
- provided	57,150	54,940	49,890
Heat content (Btu/cf, LHV)	920	920	920
Fuel density (lb/ft^3)	0.0437	0.0437	0.0437
Fuel usage (cf/hr)- calculated	1,395,652	1,310,870	1,169,565
Stack and Exit Gas Conditions- HRSG			
Stack height (ft)	125	125	125
Diameter (ft)	19.0	19.0	19.0
Temperature (°F)	190	190	190
HRSG- Volume flow (acfm) = CT Volume flow (acfm) x [(HRSG Temp. (°F) + 460 K) / (CT Temp. (°F) + 460)]			
CT Volume flow (acfm)	1,939,295	1,891,657	1,781,152
CT Temperature (°F)	1,051	1,087	1,089
HRSG Temperature (°F)	190	190	190
HRSG Volume flow (acfm)	834,243	794,814	747,417
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2/4) x 3.14159] / 60 sec/min			
Volume flow (acfm)	834,243	794,814	747,417
Diameter (ft)	19.0	19.0	19.0
Velocity (ft/sec)- calculated	49.0	46.7	43.9

Source: Siemens-Westinghouse, 2000.

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2

Table A-10. Maximum Emissions for Criteria and Other Regulated Pollutants for the FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Natural Gas, 65 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	105 °F
Hours of Operation	8,760	8,760	8,760
Particulate from CT and SCR			
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer (front- and back-half)			
Basis, lb/hr [a]	5.7	5.4	4.9
Particulate from SCR = Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (= PM_{10})			
Particulate from conversion of SO_2= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	4.0	3.7	3.3
Conversion (%) from SO_2 to SO_3	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7
Particulate (lb/hr)- calculated	0.82	0.77	0.69
Particulate (lb/hr) from CT + SCR	6.5	6.2	5.6
(TPY)	28.6	27.0	24.5
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2/lb S) /100			
Fuel use (cf/hr)	1,395,652	1,310,870	1,169,565
Sulfur content (grains/ 100 cf) - assumed [b]	1	1	1
lb SO_2/lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	4.0	3.7	3.3
(lb/hr)- provided (0.2 gr/100 cf) (not used)	0.81	0.78	0.71
(TPY)	17.5	16.4	14.6
Nitrogen Oxides (lb/hr)= NO_x(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2 [a,d]	3.5	3.5	3.5
Moisture (%)	7.17	7.84	10.90
Oxygen (%)	13.19	13.14	12.83
Volume Flow (acfm)	1,939,295	1,891,657	1,781,152
Temperature (°F)	1,051	1,087	1,089
Emission rate (lb/hr)- calculated	17.9	16.8	14.9
(lb/hr)- provided	18.7	17.5	15.8
(TPY)	81.8	76.7	69.0
[Ratio lb/hr provided/calculated]	1.044	1.042	1.054
Carbon Monoxide (lb/hr)= CO(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd- calculated	11.3	11.3	11.0
Basis, ppmvd @ 15% O_2 - calculated	10	10	10
- provided [a]	10	10	10
Moisture (%)	7.17	7.84	10.90
Oxygen (%)	13.19	13.14	12.83
Volume Flow (acfm)	1,939,295	1,891,657	1,781,152
Temperature (°F)	1,051	1,087	1,089
Emission rate (lb/hr)- calculated from given pp	31.1	29.2	26.0
(lb/hr)- provided	33.0	31.0	28.0
(TPY)	144.5	135.8	122.6
[Ratio lb/hr provided/calculated]	1.061	1.062	1.078
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/ 100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd (as CH_4)- calculated	#NAME?	#NAME?	#NAME?
Basis, ppmvd @ 15% O_2 - calculated	#NAME?	#NAME?	#NAME?
- provided [a,c]	#NAME?	#NAME?	#NAME?
Moisture (%)	7.17	7.84	10.90
Oxygen (%)	13.19	13.14	12.83
Volume Flow (acfm)	1,939,295	1,891,657	1,781,152
Temperature (°F)	1,051	1,087	1,089
Emission rate (lb/hr)- calculated	#NAME?	#NAME?	#NAME?
(lb/hr)- provided	#NAME?	#NAME?	#NAME?
(TPY)	#NAME?	#NAME?	#NAME?
[Ratio lb/hr provided/calculated]	#NAME?	#NAME?	#NAME?
Lead (lb/hr)= NA			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA
(TPY)	NA	NA	NA
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu [c]	8.00E-04	8.00E-04	8.00E-04
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	1.14E-06	1.07E-06	9.47E-07
(TPY)	4.99E-06	4.68E-06	4.15E-06
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4/MW SO_2 (98/64)			
SO_2 emission rate (lb/hr)	4.0	3.7	3.3
lb H_2SO_4/lb SO_2 (98/64)	1.53	1.53	1.53
Conversion to H_2SO_4 (%) [b]	10	10	10
Emission Rate (lb/hr)	0.61	0.57	0.51
(TPY)	2.67	2.51	2.24

Source: [a] Siemens-Westinghouse, 2000.
[b] Golder Associates Inc. 2000.
[c] Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
[d] For NO_x emissions, data originally provided at 25 ppmvd at 15% oxygen.

Table A-11. Maximum Emissions for Other Regulated PSD Pollutants for the FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Natural Gas, 65 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F	59 °F	105 °F
	0	0	0
Hours of Operation	8,760	8,760	8,760
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E-06	1.20E-06	1.20E-06
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	1.71E-09	1.60E-09	1.42E-09
(TPY)	7.49E-09	7.02E-09	6.22E-09
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-12. Maximum Emissions for Hazardous Air Pollutants for the FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Natural Gas, 65 % Load

Parameter	Ambient/Compressor Inlet Temperature 20 °F 0	59 °F 0	105 °F 0
Hours of Operation	8,760	8,760	8,760
Antimony (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Benzene (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	8.00E-01	8.00E-01	8.00E-01
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	1.14E-03	1.07E-03	9.47E-04
(TPY)	4.99E-03	4.68E-03	4.15E-03
Cadmium (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Chromium (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Formaldehyde (lb/hr) = 10% of VOC lb/hr			
Emission Rate, lb/10¹² Btu	#NAME?	#NAME?	#NAME?
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	#NAME?	#NAME?	#NAME?
(TPY)	#NAME?	#NAME?	#NAME?
Cobalt (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Manganese (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Nickel (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Phosphorous (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Selenium (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	0.00E+00	0.00E+00	0.00E+00
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	0.00E+00	0.00E+00	0.00E+00
(TPY)	0.00E+00	0.00E+00	0.00E+00
Toluene (lb/hr) = Basis (lb/10¹² Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10¹² Btu			
Basis, lb/10¹² Btu	1.00E+01	1.00E+01	1.00E+01
Heat Input Rate (MMBtu/hr)	1,425	1,336	1,184
Emission Rate (lb/hr)	1.43E-02	1.34E-02	1.18E-02
(TPY)	6.24E-02	5.85E-02	5.19E-02

Source: Electric Power Research Institute (EPRI), Electric Utility Trace Substances Report, 1994 (Table B-12).
Emission factors for metals are questionable and not used.

Table A-13. Design Information and Stack Parameters for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 100 % Load

Parameter		Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Combustion Turbine Performance					
Gross power output (MW) - Estimated		191.9	184.5	178.4	163.1
Gross heat rate (Btu/kWh, LHV) - Calculated		9,513	9,101	9,109	9,094
(Btu/kWh, HHV) - Calculated		10,945	10,470	10,480	10,463
Heat Input (MMBtu/hr, LHV) - Calculated		1,825	1,679	1,625	1,483
(MMBtu/hr, HHV) - Calculated		2,100	1,932	1,870	1,707
(MMBtu/hr, HHV) - Provided		2,100	1,932	1,870	1,707
Fuel heating value (Btu/lb, LHV)		17,290	17,290	17,290	17,290
(Btu/lb, HHV)		19,892	19,892	19,892	19,892
(HHV/LHV)		1.150	1.150	1.150	1.150
CT Exhaust Flow					
Mass Flow (lb/hr)		3,826,829	3,680,420	3,558,433	3,253,093
		3,826,829	3,680,420	3,558,433	3,253,093
Temperature (°F) - Estimated		1,070	1,100	1,110	1,130
Moisture (% Vol.)		7.12	7.74	8.79	11.04
Oxygen (% Vol.)		11.99	11.99	11.78	11.40
Molecular Weight		28.78	28.68	28.56	28.32
Fuel Usage					
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))					
Heat input (MMBtu/hr, LHV)		1,825	1,679	1,625	1,483
Heat content (Btu/lb, LHV)		17,290	17,290	17,290	17,290
Fuel usage (lb/hr)- calculated		105,570	97,130	94,000	85,790
- provided		105,570	97,130	94,000	85,790
(gallons/hr) - calculated lb/gal =	7.1	14,869	13,680	13,239	12,083
HRSG Stack					
CT - Stack height (ft)		125	125	125	125
Diameter (ft)		19	19	19	19
Turbine Flow Conditions					
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)) / [Molecular weight x 2116.8] / 60 min/hr					
Mass flow (lb/hr)		3,826,829	3,680,420	3,558,433	3,253,093
Temperature (°F)		1,070	1,100	1,110	1,130
Molecular weight		28.78	28.68	28.56	28.32
Volume flow (acfm)- calculated		2,475,210	2,434,870	2,379,489	2,222,073
(ft3/s)- calculated		41,254	40,581	39,658	37,035
HRSG Stack Flow Conditions					
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2/4) x 3.14159] / 60 sec/min					
CT Temperature (°F)		270	270	270	270
CT volume flow (acfm)		1,180,983	1,139,394	1,106,387	1,020,197
Diameter (ft)		19	19	19	19
Velocity (ft/sec)- calculated		69.4	67.0	65.0	60.0

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: Siemens/Westinghouse 2000,

Table A-14. Maximum Emissions for Criteria Pollutants for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 100 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	43	39.6	38.3	34.8
Emission rate (lb/hr)- provided	43.0	39.6	38.3	34.8
Particulate from SCR= Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (=PM_{10})				
Particulate from conversion of SO_3= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	105.6	97.1	94.0	85.8
Conversion (%) from SO_2 to SO_3	10	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
Particulate (lb/hr)- calculated	21.77	20.03	19.39	17.69
Particulate (lb/hr) from CT + SCR	64.8	59.6	57.7	52.5
Particulate (tons/year) from CT + SCR	32.4	29.8	28.8	26.2
Sulfur Dioxide (lb/hr) = Natural gas (lb/hr) x sulfur content (%/100) x (lb SO_2 /lb S)				
Fuel Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel use (lb/hr)	105,570	97,130	94,000	85,790
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr) - calculated	105.6	97.1	94.0	85.8
- provided	95	95	94	86
(TPY)	52.79	48.57	47.00	42.90
Nitrogen Oxides (lb/hr) = NO_x(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	15	15	15	15
Moisture (%)	7.12	7.74	8.79	11.04
Oxygen (%)	11.99	11.99	11.78	11.4
Turbine Flow (acfm)	1,180,983	1,139,394	1,106,387	1,020,197
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	115.4	109.4	106.1	96.6
- provided	116.9	109.4	105.9	96.7
(TPY)	58.5	54.7	53.0	48.4
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	30	30	30	30
Moisture (%)	7.12	7.74	8.79	11.04
Turbine Flow (acfm)	1,180,983	1,139,394	1,106,387	1,020,197
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	103.8	99.4	95.5	85.8
- provided	112.0	106.0	102.0	91.0
(TPY)	56.0	53.0	51.0	45.5
VOCs (lb/hr) = VOC(ppmvw) x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	10	10	10	10
Turbine Flow (acfm)	1,180,983	2,434,870	2,379,489	2,222,073
Turbine Exhaust Temperature (°F)	270	1,100	1,110	1,130
Emission rate (lb/hr) - calculated	21.28	20.53	19.93	18.38
- provided	22.0	21.0	21.0	19.0
(TPY)	11.0	10.5	10.5	9.5
Lead (lb/hr)= NA				
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8	10.8
Emission rate (lb/hr)	0.0227	0.0209	0.0202	0.0184
(TPY)	0.0113	0.0104	0.0101	0.0092

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: Siemens/Westinghouse, 2000; Golder Associates, 2000; EPA, 1996 (AP-42 draft revisions)

Table A-15. Maximum Emissions for Other Regulated PSD Pollutants for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 100 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	2.10E+03	1.93E+03	1.87E+03	1.87E+03
Emission Rate (lb/hr)	7.98E-07	7.34E-07	7.11E-07	7.11E-07
(TPY)	3.99E-07	3.67E-07	3.55E-07	3.55E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	6.95E-04	6.40E-04	6.19E-04	6.19E-04
(TPY)	3.48E-04	3.20E-04	3.09E-04	3.09E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	6.83E-02	6.29E-02	6.08E-02	6.08E-02
(TPY)	3.42E-02	3.14E-02	3.04E-02	3.04E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [c], lb/10^{12} Btu	2.07E+02	2.07E+02	2.07E+02	2.07E+02
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	4.34E-01	3.99E-01	3.87E-01	3.87E-01
(TPY)	2.17E-01	2.00E-01	1.93E-01	1.93E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	1.31E-03	1.21E-03	1.17E-03	1.17E-03
(TPY)	6.57E-04	6.05E-04	5.85E-04	5.85E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	105,570	97,130	94,000	85,790
Sulfur (lb/hr)	52.79	48.57	47.00	42.90
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) (d)	10	10	10	10
Emission Rate (lb/hr)	16.17	14.87	14.39	13.14
(TPY)	8.08	7.44	7.20	6.57

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-16. Maximum Emissions for Hazardous Air Pollutants for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 100 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	1.66E-02	1.53E-02	1.48E-02	1.48E-02
(TPY)	8.31E-03	7.64E-03	7.40E-03	7.40E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	2.31E-03	2.13E-03	2.06E-03	2.06E-03
(TPY)	1.15E-03	1.06E-03	1.03E-03	1.03E-03
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	6.80E-03	6.26E-03	6.06E-03	6.06E-03
(TPY)	3.40E-03	3.13E-03	3.03E-03	3.03E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	1.42E-02	1.31E-02	1.26E-02	1.26E-02
(TPY)	7.10E-03	6.53E-03	6.32E-03	6.32E-03
Formaldehyde (lb/hr) = 10% of VOC lb/hr				
Emission Rate, lb/10^{12} Btu	1.05E+03	1.05E+03	1.05E+03	1.05E+03
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	2.20E+00	2.02E+00	1.96E+00	1.96E+00
(TPY)	1.10E+00	1.01E+00	9.79E-01	9.79E-01
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	37	37	37	37
Heat Input Rate (MMBtu/hr)	2.10E+03	1.93E+03	1.87E+03	1.87E+03
Emission Rate (lb/hr)	7.77E-02	7.15E-02	6.92E-02	6.92E-02
(TPY)	3.88E-02	3.57E-02	3.46E-02	3.46E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	432	432	432	432
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	9.07E-01	8.35E-01	8.08E-01	8.08E-01
(TPY)	4.54E-01	4.17E-01	4.04E-01	4.04E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	86.3	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	1.81E-01	1.67E-01	1.61E-01	1.61E-01
(TPY)	9.06E-02	8.34E-02	8.07E-02	8.07E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	0.629999532	0.579632988	0.5609544	0.5609544
(TPY)	0.314999766	0.289816494	0.2804772	0.2804772
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	23	23	23	23
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	4.83E-02	4.44E-02	4.30E-02	4.30E-02
(TPY)	2.41E-02	2.22E-02	2.15E-02	2.15E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	237	237	237	237
Heat Input Rate (MMBtu/hr)	2,100	1,932	1,870	1,870
Emission Rate (lb/hr)	4.98E-01	4.58E-01	4.43E-01	4.43E-01
(TPY)	2.49E-01	2.29E-01	2.22E-01	2.22E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1996 (AP-42, Table 3.1-4)

Table A-17. Design Information and Stack Parameters for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 80 % Load

Parameter		Turbine Inlet Temperature		
	20 °F	59 °F	72 °F	105 °F
Combustion Turbine Performance				
Gross power output (MW) - Estimated	153.5	147.6	142.7	130.5
Gross heat rate (Btu/kWh, LHV) - Calculated	9,642	9,295	9,335	9,412
(Btu/kWh, HHV) - Calculated	10,707	10,321	10,366	10,452
Heat Input (MMBtu/hr, LHV) - Calculated	1,480	1,372	1,332	1,228
(MMBtu/hr, HHV) - Calculated	1,644	1,524	1,480	1,364
(MMBtu/hr, HHV) - Provided	1,644	1,524	1,480	1,364
Fuel heating value (Btu/lb, LHV)	17,290	17,290	17,290	17,290
(Btu/lb, HHV)	19,200	19,200	19,200	19,200
(HHV/LHV)	1.110	1.110	1.110	1.110
CT Exhaust Flow				
Mass Flow (lb/hr)	3,800,715	3,589,967	3,459,546	3,179,611
	3,800,715	3,589,967	3,459,546	3,179,611
Temperature (°F) - Estimated	1,120	1,140	1,150	1,170
Moisture (% Vol.)	5.85	6.53	7.6	9.9
Oxygen (% Vol.)	13.42	13.38	13.17	12.73
Molecular Weight	28.81	28.73	28.61	28.36
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))				
Heat input (MMBtu/hr, LHV)	1,480	1,372	1,332	1,228
Heat content (Btu/lb, LHV)	17,290	17,290	17,290	17,290
Fuel usage (lb/hr)- calculated	85,600	79,360	77,060	71,030
- provided	85,600	79,360	77,060	71,030
(gallons/hr) - calculated lb/gal = 7.1	12,056	11,177	10,854	10,004
HRSG Stack				
CT - Stack height (ft)	125	125	125	125
Diameter (ft)	19	19	19	19
Turbine Flow Conditions				
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr				
Mass flow (lb/hr)	3,800,715	3,589,967	3,459,546	3,179,611
Temperature (°F)	1,120	1,140	1,150	1,170
Molecular weight	28.81	28.73	28.61	28.36
Volume flow (acfm)- calculated	2,535,697	2,431,994	2,368,159	2,223,331
(ft3/s)- calculated	42,262	40,533	39,469	37,056
HRSG Stack Flow Conditions				
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2/4) x 3.14159] / 60 sec/min				
CT Temperature (°F)	270	270	270	270
CT volume flow (acfm)	1,171,556	1,109,597	1,073,761	995,725
Diameter (ft)	19	19	19	19
Velocity (ft/sec)- calculated	68.9	65.2	63.1	58.5

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^2
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: Siemens/Westinghouse 2000,

Table A-18. Maximum Emissions for Criteria Pollutants for FPC Hines-2 Energy Center
. Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 80 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	34.7	32.2	31.2	29.7
Emission rate (lb/hr)- provided	34.7	32.2	31.2	29.7
Particulate from SCR = Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (= PM_{10})				
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	85.6	79.4	77.1	71.0
Conversion (%) from SO_2 to SO_3	10	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
Particulate (lb/hr)- calculated	17.66	16.37	15.89	14.65
Particulate (lb/hr) from CT + SCR	52.4	48.6	47.1	44.3
Particulate (tons/year) from CT + SCR	26.2	24.3	23.5	22.2
Sulfur Dioxide (lb/hr) = Natural gas (lb/hr) x sulfur content (%/100) x (lb SO_2/lb S)				
Fuel Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel use (lb/hr)	85,600	79,360	77,060	71,030
lb SO_2/lb S (64/32)	2	2	2	2
Emission rate (lb/hr) - calculated	85.6	79.4	77.1	71.0
- provided	86	79	77	71
(TPY)	42.80	39.68	38.53	35.52
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	15	15	15	15
Moisture (%)	5.85	6.53	7.6	9.9
Oxygen (%)	13.42	13.38	13.17	12.73
Turbine Flow (acfm)	1,171,556	1,109,597	1,073,761	995,725
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	96.5	89.9	86.8	80.0
- provided	96.6	89.4	86.9	80.0
(TPY)	48.3	44.7	43.5	40.0
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	30	30	30	30
Moisture (%)	5.85	6.53	7.6	9.9
Turbine Flow (acfm)	1,171,556	1,109,597	1,073,761	995,725
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	104.3	98.1	93.9	84.9
- provided	111.0	103.0	100.0	89.0
(TPY)	55.5	51.5	50.0	44.5
VOCs (lb/hr) = VOC(ppmvw) x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	10	10	10	10
Turbine Flow (acfm)	1,171,556	2,431,994	2,368,159	2,223,331
Turbine Exhaust Temperature (°F)	270	1,140	1,150	1,170
Emission rate (lb/hr) - calculated	21.11	19.99	19.35	17.94
- provided	21.0	22.0	21.0	19.0
(TPY)	10.5	11.0	10.5	9.5
Lead (lb/hr) = NA				
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8	10.8
Emission rate (lb/hr)	0.0178	0.0165	0.0160	0.0147
(TPY)	0.0089	0.0082	0.0080	0.0074

Note: ppmvd = parts per million, volume dry; O_2 = oxygen.

Source: Siemens/Westinghouse, 2000; Golder Associates, 2000; EPA, 1996 (AP-42 draft revisions).

Table A-19. Maximum Emissions for Other Regulated PSD Pollutants for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 80 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1.64E+03	1.52E+03	1.48E+03	1.48E+03
Emission Rate (lb/hr)	6.25E-07	5.79E-07	5.62E-07	5.62E-07
(TPY)	3.12E-07	2.90E-07	2.81E-07	2.81E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	5.44E-04	5.04E-04	4.90E-04	4.90E-04
(TPY)	2.72E-04	2.52E-04	2.45E-04	2.45E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	5.35E-02	4.96E-02	4.81E-02	4.81E-02
(TPY)	2.67E-02	2.48E-02	2.41E-02	2.41E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [c], lb/10^{12} Btu	2.14E+02	2.14E+02	2.14E+02	2.14E+02
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	3.52E-01	3.26E-01	3.17E-01	3.17E-01
(TPY)	1.76E-01	1.63E-01	1.58E-01	1.58E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.03E-03	9.54E-04	9.26E-04	9.26E-04
(TPY)	5.14E-04	4.77E-04	4.63E-04	4.63E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	85,600	79,360	77,060	71,030
Sulfur (lb/hr)	42.80	39.68	38.53	35.52
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) [d]	10	10	10	10
Emission Rate (lb/hr)	13.11	12.15	11.80	10.88
(TPY)	6.55	6.08	5.90	5.44

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[d] assumed based on combustion estimates from GE

Table A-20. Maximum Emissions for Hazardous Air Pollutants for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 80 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.30E-02	1.21E-02	1.17E-02	1.17E-02
(TPY)	6.50E-03	6.03E-03	5.85E-03	5.85E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.81E-03	1.68E-03	1.63E-03	1.63E-03
(TPY)	9.04E-04	8.38E-04	8.14E-04	8.14E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	5.33E-03	4.94E-03	4.79E-03	4.79E-03
(TPY)	2.66E-03	2.47E-03	2.40E-03	2.40E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.11E-02	1.03E-02	1.00E-02	1.00E-02
(TPY)	5.56E-03	5.15E-03	5.00E-03	5.00E-03
Formaldehyde (lb/hr) = 10% of VOC lb/hr				
Emission Rate, lb/10^{12} Btu	1.28E+03	1.28E+03	1.28E+03	1.28E+03
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	2.10E+00	1.95E+00	1.89E+00	1.89E+00
(TPY)	1.05E+00	9.73E-01	9.45E-01	9.45E-01
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	37	37	37	37
Heat Input Rate (MMBtu/hr)	1.64E+03	1.52E+03	1.48E+03	1.48E+03
Emission Rate (lb/hr)	6.08E-02	5.64E-02	5.47E-02	5.47E-02
(TPY)	3.04E-02	2.82E-02	2.74E-02	2.74E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	432	432	432	432
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	7.10E-01	6.58E-01	6.39E-01	6.39E-01
(TPY)	3.55E-01	3.29E-01	3.20E-01	3.20E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	86.3	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	1.42E-01	1.31E-01	1.28E-01	1.28E-01
(TPY)	7.09E-02	6.57E-02	6.38E-02	6.38E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	0.493056	0.4571136	0.4438656	0.4438656
(TPY)	0.246528	0.2285568	0.2219328	0.2219328
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	23	23	23	23
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	3.78E-02	3.50E-02	3.40E-02	3.40E-02
(TPY)	1.89E-02	1.75E-02	1.70E-02	1.70E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	237	237	237	237
Heat Input Rate (MMBtu/hr)	1,644	1,524	1,480	1,480
Emission Rate (lb/hr)	3.90E-01	3.61E-01	3.51E-01	3.51E-01
(TPY)	1.95E-01	1.81E-01	1.75E-01	1.75E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1996 (AP-42, Table 3.1-4)

Table A-21. Design Information and Stack Parameters for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 65 % Load

Parameter		Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Combustion Turbine Performance					
Gross power output (MW) - Estimated		124.7	119.9	116.0	106.0
Gross heat rate (Btu/kWh, LHV) - Calculated		9,997	9,733	9,834	10,036
(Btu/kWh, HHV) - Calculated		11,101	10,808	10,920	11,145
Heat Input (MMBtu/hr, LHV) - Calculated		1,247	1,167	1,140	1,064
(MMBtu/hr, HHV) - Calculated		1,385	1,296	1,266	1,182
(MMBtu/hr, HHV) - Provided		1,385	1,296	1,266	1,182
Fuel heating value (Btu/lb, LHV)		17,290	17,290	17,290	17,290
(Btu/lb, HHV)		19,200	19,200	19,200	19,200
(HHV/LHV)		1.110	1.110	1.110	1.110
CT Exhaust Flow					
Mass Flow (lb/hr)		3,491,217	3,298,903	3,219,964	3,009,818
		3,491,217	3,298,903	3,219,964	3,009,818
Temperature (°F) - Estimated		1,170	1,180	1,190	1,200
Moisture (% Vol.)		4.99	5.71	6.78	9.08
Oxygen (% Vol.)		14.12	14.04	13.83	13.41
Molecular Weight		28.87	28.79	28.66	28.41
Fuel Usage					
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))					
Heat input (MMBtu/hr, LHV)		1,247	1,167	1,140	1,064
Heat content (Btu/lb, LHV)		17,290	17,290	17,290	17,290
Fuel usage (lb/hr)- calculated		72,110	67,520	65,960	61,540
- provided		72,110	67,520	65,960	61,540
(gallons/hr) - calculated lb/gal=	7.1	10,156	9,510	9,290	8,668
HRSG Stack					
CT - Stack height (ft)		125	125	125	125
Diameter (ft)		19	19	19	19
Turbine Flow Conditions					
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr					
Mass flow (lb/hr)		3,491,217	3,298,903	3,219,964	3,009,818
Temperature (°F)		1,170	1,180	1,190	1,200
Molecular weight		28.87	28.79	28.66	28.41
Volume flow (acfm)- calculated		2,397,803	2,286,301	2,255,019	2,139,484
(ft3/s)- calculated		39,963	38,105	37,584	35,658
HRSG Stack Flow Conditions					
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min					
CT Temperature (°F)		270	270	270	270
CT volume flow (acfm)		1,073,863	1,017,683	997,675	940,858
Diameter (ft)		19	19	19	19
Velocity (ft/sec)- calculated		63.1	59.8	58.6	55.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft^2; 14.7 lb/ft^3
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: Siemens/Westinghouse 2000,

Table A-21. Design Information and Stack Parameters for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 65 % Load

Parameter		Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Combustion Turbine Performance					
Gross power output (MW) - Estimated		124.7	119.9	116.0	106.0
Gross heat rate (Btu/kWh, LHV) - Calculated		9,997	9,733	9,834	10,036
(Btu/kWh, HHV) - Calculated		11,101	10,808	10,920	11,145
Heat Input (MMBtu/hr, LHV) - Calculated		1,247	1,167	1,140	1,064
(MMBtu/hr, HHV) - Calculated		1,385	1,296	1,266	1,182
(MMBtu/hr, HHV) - Provided		1,385	1,296	1,266	1,182
Fuel heating value (Btu/lb, LHV)		17,290	17,290	17,290	17,290
(Btu/lb, HHV)		19,200	19,200	19,200	19,200
(HHV/LHV)		1.110	1.110	1.110	1.110
CT Exhaust Flow					
Mass Flow (lb/hr)		3,491,217	3,298,903	3,219,964	3,009,818
		3,491,217	3,298,903	3,219,964	3,009,818
Temperature (°F) - Estimated		1,170	1,180	1,190	1,200
Moisture (% Vol.)		4.99	5.71	6.78	9.08
Oxygen (% Vol.)		14.12	14.04	13.83	13.41
Molecular Weight		28.87	28.79	28.66	28.41
Fuel Usage					
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu (Fuel Heat Content, Btu/lb (LHV))					
Heat input (MMBtu/hr, LHV)		1,247	1,167	1,140	1,064
Heat content (Btu/lb, LHV)		17,290	17,290	17,290	17,290
Fuel usage (lb/hr)- calculated		72,110	67,520	65,960	61,540
- provided		72,110	67,520	65,960	61,540
(gallons/hr) - calculated lb/gal=	7.1	10,156	9,510	9,290	8,668
HRSG Stack					
CT - Stack height (ft)		125	125	125	125
Diameter (ft)		19	19	19	19
Turbine Flow Conditions					
Turbine Flow (acfm) = [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] / [Molecular weight x 2116.8] / 60 min/hr					
Mass flow (lb/hr)		3,491,217	3,298,903	3,219,964	3,009,818
Temperature (°F)		1,170	1,180	1,190	1,200
Molecular weight		28.87	28.79	28.66	28.41
Volume flow (acfm)- calculated		2,397,803	2,286,301	2,255,019	2,139,484
(ft3/s)- calculated		39,963	38,105	37,584	35,658
HRSG Stack Flow Conditions					
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min					
CT Temperature (°F)		270	270	270	270
CT volume flow (acfm)		1,073,863	1,017,683	997,675	940,858
Diameter (ft)		19	19	19	19
Velocity (ft/sec)- calculated		63.1	59.8	58.6	55.3

Note: Universal gas constant = 1,545 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft²; 14.7 lb/ft³
Turbine inlet relative humidity is 20% at 35 °F, 60% at 59 and 75 °F, and 50% at 95 °F.
Source: Siemens/Westinghouse 2000,

Table A-22. Maximum Emissions for Criteria Pollutants for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 65 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	28.6	27	26.3	24.5
Emission rate (lb/hr)- provided	28.6	27.0	26.3	24.5
Particulate from SCR= Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (=PM_{10})				
Particulate from conversion of SO_2= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3				
SO_2 emission rate (lb/hr)- calculated	72.1	67.5	66.0	61.5
Conversion (%) from SO_2 to SO_3	10	10	10	10
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7	1.7
Particulate (lb/hr)- calculated	14.87	13.93	13.60	12.69
Particulate (lb/hr) from CT + SCR	43.5	40.9	39.9	37.2
Particulate (tons/year) from CT + SCR	21.7	20.5	20.0	18.6
Sulfur Dioxide (lb/hr) = Natural gas (lb/hr) x sulfur content (%/100) x (lb SO_2 /lb S)				
Fuel Sulfur Content	0.05%	0.05%	0.05%	0.05%
Fuel use (lb/hr)	72,110	67,520	65,960	61,540
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr) - calculated	72.1	67.5	66.0	61.5
- provided	72	68	66	62
(TPY)	36.06	33.76	32.98	30.77
Nitrogen Oxides (lb/hr) = NO_x(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NO_x) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	15	15	15	15
Moisture (%)	4.99	5.71	6.78	9.08
Oxygen (%)	14.12	14.04	13.83	13.41
Turbine Flow (acfm)	1,073,863	1,017,683	997,675	940,858
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	81.1	75.9	74.3	69.3
- provided	81.2	76.0	74.3	69.3
(TPY)	40.6	38.0	37.2	34.7
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	30	30	30	30
Moisture (%)	4.99	5.71	6.78	9.08
Turbine Flow (acfm)	1,073,863	1,017,683	997,675	940,858
Turbine Exhaust Temperature (°F)	270	270	270	270
Emission rate (lb/hr) - calculated	96.5	90.8	88.0	80.9
- provided	101.0	94.0	92.0	86.0
(TPY)	50.5	47.0	46.0	43.0
VOCs (lb/hr) = VOC(ppmvw) x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvw	10	10	10	10
Turbine Flow (acfm)	1,073,863	2,286,301	2,255,019	2,139,484
Turbine Exhaust Temperature (°F)	270	1,180	1,190	1,200
Emission rate (lb/hr) - calculated	19.35	18.34	17.98	16.95
- provided	20.0	19.0	18.0	19.0
(TPY)	10.0	9.5	9.0	9.5
Lead (lb/hr)= NA				
Emission Rate Basis (lb/10^{12} Btu)	10.8	10.8	10.8	10.8
Emission rate (lb/hr)	0.0150	0.0140	0.0137	0.0128
(TPY)	0.0075	0.0070	0.0068	0.0064

Note: ppmvd = parts per million, volume dry; O_2= oxygen.

Source: Siemens/Westinghouse, 2000; Golder Associates, 2000; EPA, 1996 (AP-42 draft revisions)

Table A-23. Maximum Emissions for Other Regulated PSD Pollutants for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_X Combustor, Distillate, 65 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
2,3,7,8 TCDD Equivalents (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	3.80E-04	3.80E-04	3.80E-04	3.80E-04
Heat Input Rate (MMBtu/hr)	1.38E+03	1.30E+03	1.27E+03	1.27E+03
Emission Rate (lb/hr)	5.26E-07	4.93E-07	4.81E-07	4.81E-07
(TPY)	2.63E-07	2.46E-07	2.41E-07	2.41E-07
Beryllium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	0.331	0.331	0.331	0.331
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	4.58E-04	4.29E-04	4.19E-04	4.19E-04
(TPY)	2.29E-04	2.15E-04	2.10E-04	2.10E-04
Fluoride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	32.54	32.54	32.54	32.54
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	4.51E-02	4.22E-02	4.12E-02	4.12E-02
(TPY)	2.25E-02	2.11E-02	2.06E-02	2.06E-02
Hydrogen Chloride (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [c], lb/10^{12} Btu	2.14E+02	2.14E+02	2.14E+02	2.14E+02
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	2.97E-01	2.78E-01	2.71E-01	2.71E-01
(TPY)	1.48E-01	1.39E-01	1.36E-01	1.36E-01
Mercury (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	6.26E-01	6.26E-01	6.26E-01	6.26E-01
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	8.67E-04	8.12E-04	7.93E-04	7.93E-04
(TPY)	4.33E-04	4.06E-04	3.96E-04	3.96E-04
Sulfuric Acid Mist = Fuel Use (lb/hr) x sulfur (S) content (fraction) x conversion of S to H_2SO_4 (%) x MW H_2SO_4 /MW S (98/32)				
Fuel Usage (cf/hr)	72,110	67,520	65,960	61,540
Sulfur (lb/hr)	36.06	33.76	32.98	30.77
lb H_2SO_4 /lb S (98/32)	3.0625	3.0625	3.0625	3.0625
Conversion to H_2SO_4 (%) [d]	10	10	10	10
Emission Rate (lb/hr)	11.04	10.34	10.10	9.42
(TPY)	5.52	5.17	5.05	4.71

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1981
[c] 4 ppm assumed based on ASTM D2880
[c] assumed based on combustion estimates from GE

Table A-24. Maximum Emissions for Hazardous Air Pollutants for FPC Hines-2 Energy Center
Siemens-Westinghouse 501F, Dry Low NO_x Combustor, Distillate, 65 % Load

Parameter	Turbine Inlet Temperature 20 °F	59 °F	72 °F	105 °F
Hours of Operation	1,000	1,000	1,000	1,000
Arsenic (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	7.91E+00	7.91E+00	7.91E+00	7.91E+00
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	1.10E-02	1.03E-02	1.00E-02	1.00E-02
(TPY)	5.48E-03	5.13E-03	5.01E-03	5.01E-03
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	1.1	1.1	1.1	1.1
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	1.52E-03	1.43E-03	1.39E-03	1.39E-03
(TPY)	7.61E-04	7.13E-04	6.97E-04	6.97E-04
Cadmium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	3.24	3.24	3.24	3.24
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	4.49E-03	4.20E-03	4.10E-03	4.10E-03
(TPY)	2.24E-03	2.10E-03	2.05E-03	2.05E-03
Chromium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	6.76	6.76	6.76	6.76
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	9.36E-03	8.76E-03	8.56E-03	8.56E-03
(TPY)	4.68E-03	4.38E-03	4.28E-03	4.28E-03
Formaldehyde (lb/hr) = 10% of VOC lb/hr				
Emission Rate, lb/10^{12} Btu	1.44E+03	1444.552304	1444.552304	1444.552304
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	2.00E+00	1.87E+00	1.83E+00	1.83E+00
(TPY)	1.00E+00	9.36E-01	9.15E-01	9.15E-01
Cobalt (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	37	37	37	37
Heat Input Rate (MMBtu/hr)	1.38E+03	1.30E+03	1.27E+03	1.27E+03
Emission Rate (lb/hr)	5.12E-02	4.80E-02	4.69E-02	4.69E-02
(TPY)	2.56E-02	2.40E-02	2.34E-02	2.34E-02
Manganese (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	432	432	432	432
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	5.98E-01	5.60E-01	5.47E-01	5.47E-01
(TPY)	2.99E-01	2.80E-01	2.74E-01	2.74E-01
Nickel (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	86.3	86.3	86.3	86.3
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	1.19E-01	1.12E-01	1.09E-01	1.09E-01
(TPY)	5.97E-02	5.59E-02	5.46E-02	5.46E-02
Phosphorous (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [b], lb/10^{12} Btu	3.00E+02	3.00E+02	3.00E+02	3.00E+02
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	0.4153536	0.3889152	0.3799296	0.3799296
(TPY)	0.2076768	0.1944576	0.1899648	0.1899648
Selenium (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	23	23	23	23
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	3.18E-02	2.98E-02	2.91E-02	2.91E-02
(TPY)	1.59E-02	1.49E-02	1.46E-02	1.46E-02
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu				
Basis [a], lb/10^{12} Btu	237	237	237	237
Heat Input Rate (MMBtu/hr)	1,385	1,296	1,266	1,266
Emission Rate (lb/hr)	3.28E-01	3.07E-01	3.00E-01	3.00E-01
(TPY)	1.64E-01	1.54E-01	1.50E-01	1.50E-01

Sources: [a] EPA, 1998 (AP-42 draft revisions)
[b] EPA, 1996 (AP-42, Table 3.1-4)

Table A-25 Summary of Maximum Potential Annual Emissions for the CT/HRSG

Pollutant		Annual Emissions (tons/year)[a]			Maximum Emissions (tons/year)[b]				PSD Significant Emission Rates
		Natural Gas	Natural Gas	Distillate Oil	Case A	Case B	Case C	Case D	
	Load:	100%	60%	100%					
	Hours:	8,760	3,000	1,000					
One Combustion Turbine- Combined Cycle									
SO_2		22.4	5.4	48.6	22.4	20.1	68.4	66.1	40
PM/PM_{10}		34.4	8.8	29.8	34.4	31.4	60.3	57.3	25/15
NO_x		101	24	55	101.2	90.4	144.3	133.5	40
CO		184	219	53	184.0	340.0	216.0	372.0	100
VOC (as methane)		19.1	7.5	10.5	19.1	20.0	27.4	28.4	40
Sulfuric Acid Mist		3.4	0.8	7.4	3.4	3.1	10.5	10.1	7
Lead		0	0.00E+00	1.04E-02	0.0E+00	0.0E+00	1.0E-02	1.0E-02	0.6
Mercury		6.41E-06	1.54E-06	6.05E-04	6.4E-06	5.8E-06	6.1E-04	6.1E-04	0.1
MWC Organics (as 2,3,7,8-TCDD)		9.62E-09	2.30E-09	3.67E-07	9.6E-09	8.6E-09	3.8E-07	3.7E-07	3.50E-06
MWC Metals (Be & Cd)		0.0	0.0	3.4E-03	0.0E+00	0.0E+00	3.4E-03	3.4E-03	15
MWC Acid Gases (HCL)		0.0	0.0	0.2	0.0	0.0	0.2	0.2	40.0
Total HAPs		1.93	0.77	1.80	1.9	2.0	3.5	3.6	25
Two Combustion Turbines- Combined Cycle									
SO_2		44.9	10.7	97.1	44.9	40.2	136.9	132.3	40
PM/PM_{10}		69	18	60	69	63	121	115	25/15
NO_x		202	48	109	202	181	289	267	40
CO		368	438	106	368	680	432	744	100
VOC (as methane)		38.1	15.0	21.0	38.1	40.1	54.8	56.7	40
Sulfuric Acid Mist		6.9	1.65	14.87	6.87	6.16	20.96	20.25	7
Lead		0.00E+00	0.00E+00	2.09E-02	0.00E+00	0.00E+00	2.09E-02	2.09E-02	0.6
Mercury		1.28E-05	3.07E-06	1.21E-03	1.28E-05	1.15E-05	1.22E-03	1.22E-03	0.1
MWC Organics (as 2,3,7,8-TCDD)		1.92E-08	4.61E-09	7.34E-07	1.92E-08	1.73E-08	7.51E-07	7.49E-07	3.50E-06
MWC Metals (Be & Cd)		0.00E+00	0.00E+00	6.90E-03	0.00E+00	0.00E+00	6.90E-03	6.90E-03	15
MWC Acid Gases (HCL)		0.0	0.00	0.40	0.00	0.00	0.40	0.40	40.0
Total HAPs		3.9	1.55	3.60	3.87	4.09	7.02	7.25	25

[a] Based on 59 °F compressor inlet air temperature

B.0 SUMMARY OF CALPUFF MODEL DESCRIPTION AND ASSUMPTIONS USED IN THE PSD CLASS I MODELING ANALYSES

B.1 INTRODUCTION

As part of the new source review requirements under Prevention of Significant Deterioration (PSD) regulations, new sources are required to address air quality impacts at PSD Class I areas. As part of the PSD analysis report submitted to the Florida Department of Environmental Protection (DEP), the air quality impacts due to the potential emissions of the proposed Power Block 2 of the Hines Energy Complex are required to be addressed at the PSD Class I area of the Chassahowitzka National Wildlife Area (NWA). The Chassahowitzka NWA is located approximately 118 km northwest of the proposed source and is the nearest Class I area to the proposed source. Other PSD Class I areas are located more than 200 km from the proposed source.

The evaluation of air quality impacts are not only concerned with determining compliance with PSD Class I increments but also assessing a source's impact on Air Quality Related Values (AQRVs), such as regional haze. Further, compliance with PSD Class I increments can be evaluated by determining if the source's impacts are less than the proposed U.S. Environmental Protection Agency (EPA) Class I significant impact levels. The significant impact levels are threshold levels that are used to determine the type of air impact analyses needed for the project. If the new source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with Class I increments.

Currently there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and Federal Land Managers (FLM) of Class I areas who are responsible for ensuring that AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM) Phase 1 Report: Interim Recommendations for Modeling Long Range Transport and Impacts on Regional Visibility* (EPA, 1993), referred to as the Phase 1 report; and
- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the Phase 2 report.

The recommended modeling approaches from these documents are as follows:

- Phase 1 report: screening analysis (Level 1)
- Phase 2 report: screening analysis
- Phase 2 report: refined analysis

For Power Block 2, air quality analyses were performed that assess the proposed source's impacts in the PSD Class I area of the Chassahowitzka NWA using the refined approach from the Phase 2 report for:

- Significant impact analysis; and
- Regional haze analysis.

The refined analysis approach was used instead of the screening analysis approach since the air quality impacts are based on generally more realistic assumptions, include more detailed meteorological data, and are estimated at locations at the Class I area.

B.2 GENERAL AIR MODELING APPROACH

The general modeling approach was based on using the Industrial Source Complex Short-term model (ISCST3, Version 99155) and the long-range transport model, California Puff model (CALPUFF, Version 5.0). The ISCST3 model is applicable for estimating the air quality impacts in areas that are within 50 km from a source. At distances beyond 50 km, the ISCST3 model is considered to overpredict air quality impacts because it is a steady-state model. At those distances, the CALPUFF model is recommended for use. Recently, the FLM have requested that air quality impacts, such as for regional haze, for a source located more than 50 km from a Class I area be predicted using the CALPUFF model. The Florida DEP has also recommended that the CALPUFF model be used to assess if the source has a significant impact at a Class I area located beyond 50 km from the source. As a result, a significant impact and regional haze analyses were performed using the CALPUFF model to assess Power Block 2's impacts at the Chassahowitzka NWA.

The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a screening analysis as presented in the *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998).

Based on discussions with DEP, the ISCST3 model can be used to determine the "worst-case" operating load and ambient temperature that produces a source's maximum impact at a Class I area. Based on that analysis, air quality impacts can then be predicted with the CALPUFF model using the "worst-case" operating scenario to compare the source's impacts to Class I significant impact levels and potential contribution to regional haze. For this proposed source, the ISCST3 model was used to determine the "worst-case" operating scenario that was then considered in the CALPUFF model. The methods and assumptions used in the ISCST3 were based on those presented in Section 6.0 of the PSD report.

A regional haze analysis was performed to determine the effect that Power Block 2's emissions will have on background regional haze levels at the Chassahowitzka NWA. In the regional haze analysis, the change in visual range, as calculated by a deciview change, was estimated for the proposed source in accordance with the IWAQM recommendations. Based on those recommendations, the CALPUFF model is used to predict the maximum 24-hour average sulfate (SO_4), nitrate (NO_3), and fine particulate (PM_{10}) concentrations as well as ammonium sulfate ($(NH_4)_2SO_4$) and ammonium nitrate (NH_4NO_3) concentrations. The change in visibility due to a source, estimated as a percentage, is then calculated based on the change from background data.

The following sections present the methods and assumptions used to assess the refined significant impact and regional haze analyses performed for the proposed source. The results of these analyses are presented in Sections 7.0 and 8.0 of the PSD report.

B.3 MODEL SELECTION AND SETTINGS

The California Puff (CALPUFF, version 5.0) air modeling system was used to assess the Power Block 2's impacts at the PSD Class I area for comparison to the PSD Class I significant impact levels and to the regional haze visibility criteria. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. CALMET was designed to process raw meteorological, terrain and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess the pollutant specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 Report (EPA, 1998).

B.3.1 CALPUFF Model Approaches and Settings

The IWAQM has recommended approaches for performing a Phase 2 refined modeling analyses that are presented in Table B-1. These approaches involve use of meteorological data, selection of receptors and dispersion conditions, and processing of model output.

The specific settings used in the CALPUFF model are presented in Table B-2.

B.3.2 Emission Inventory and Building Wake Effects

The CALPUFF model included the proposed source's emission, stack, and operating data as well as building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model input. The PSD Analysis Report presents a listing of the proposed source's emissions and structures included in the analysis.

B.4 RECEPTOR LOCATIONS

For the refined analyses, pollutant concentrations were predicted in an array of 13 discrete receptors located at the CNWR area. These receptors are the same as those used in the PSD Class I analysis performed for the PSD Analysis Report.

B.5 METEOROLOGICAL DATA

B.5.1 Refined Analysis

CALMET was used to develop the gridded parameter fields required for the refined modeling analyses. The follow sections discuss the specific data used and processed in the CALMET model.

B.5.2 CALMET Settings

The CALMET settings contained in Table B-3 were used for the refined modeling analysis. With the exception of hourly precipitation data files, all input data files needed for CALMET were developed by the FDEP staff.

B.5.3 Modeling Domain

A rectangular modeling domain extending 250 km in the east-west (x) direction and 280 km in the north-south (y) direction was used for the refined modeling analysis. The extent of the modeling domain was selected by the Florida DEP staff for predicting impacts at the Chassahowitzka NWA. The southwest corner of the domain is the origin and is located at 27 degrees north latitude and 83.5 degrees west longitude. This location is in the Gulf of Mexico approximately 110 km west of Venice, Florida. For the processing of meteorological and geophysical data, the domain contains 25 grid cells in the x-direction and 28 grid cells in the y-direction. The domain grid resolution is 10 km. The air modeling analysis was performed in the UTM coordinate system.

B.5.4 Mesoscale Model – Generation 4 (MM4) Data

Pennsylvania State University in conjunction with the NCAR Assessment Laboratory developed the MM4 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for eight standard levels and up to 15 significant levels) are extensive and only allow for one data base set for the year 1990. The analysis used the MM4 data to initialize the CALMET wind field. The MM4 data have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain.

The MM4 subset domain was provided by FDEP and consisted of a 6 x 6- cell rectangle, with 80 km grid resolution, extending from the MM4 grid points (49,10) to (54,15). These data were processed to create a MM4.DAT file, for input to the CALMET model.

The MM4 data set used in the CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

B.5.5 Surface Data Stations and Processing

The surface station data processed for the CALPUFF analyses consisted of data from five NWS stations or Federal Aviation Administration (FAA) Flight Service stations for Gainesville, Tampa, Daytona Beach, Vero Beach, Fort Myers and Orlando. A summary of the surface station information and locations are presented in Table B-4. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The surface station data were processed by FDEP into a SURF.DAT file format for CALMET input.

Because the modeling domain extends largely over water, C-Man station data from Venice was obtained. These data were processed by Florida DEP into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. The over-water station data include wind direction, wind speed and air temperature.

B.5.6 Upper Air Data Stations and Processing

The analysis included three upper air NWS stations located in Ruskin, Apalachicola, and West Palm Beach. Data for each station were obtained from the Florida DEP in a format for CALMET input.

The data and locations for the upper air stations are presented in Table B-4.

B.5.7 Precipitation Data stations and Processing

Precipitation data were processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation-recording stations located within the latitude and longitudinal limits of the modeling domain. Data for 14 stations were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were then used to process the data into the format for the PRECIP.DAT file that is used by CALMET. A listing of the precipitation stations used for the modeling analysis is presented in Table B-5.

B.5.8 Geophysical Data Processing

The land-use and terrain information data were developed by the FDEP for the modeling domain and were provided in a GEO.DAT file format for input to CALMET. Terrain elevations for each grid cell of the modeling domain were obtained from Digital Elevation Model (DEM) files obtained from US Geographical Survey (USGS). The DEM data was extracted for the modeling domain grid using the utility extraction program LCELEV. Land-use data were obtained from the USGS GIS.DAT which is based on the ARM3 data. The resolution of the GIS.DAT file is one-eighth of a degree in the east-west direction and one-twelfth of a degree in the north-south direction. Land-use values for the domain grid were obtained with the utility program CAL-LAND. Other parameters processed for the modeling domain by CAL-LAND include surface roughness, surface Albedo, Bowen ratio, soil heat flux, and leaf index field. The land-use parameter values were based on annual averaged values.

Table B-1. IWAQM Phase 2 Refined Modeling Analyses Recommendations [a]	
Model Input/Output	Description
Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and sources being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; obtain regulatory concurrence on coverage.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition. 3. Define background values for ozone and ammonia for area.
Processing	1. For PSD increments: Use highest, second highest 3-hour and 24-hour average SO_2 concentrations; highest, second highest 24-hour average PM_{10} concentrations; and highest annual average SO_2, PM_{10} and NO_2 concentrations. 2. For haze: process the 24-hour average SO_4, NO_3 and HNO_3 values; compute a 24-hour average relative humidity factor (f(RH)) for the day during which the highest concentration was predicted for each species; calculate extinction coefficients for each species; and compute percent change in extinction using the FLM supplied background extinction.

[a] *IWAQM Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998)

Table B-2. CALPUFF Model Settings	
Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_X, HNO_3, and NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	PCRAMMET (enhanced) for the screening analysis; CALMET for the refined analysis
Plume Rise	Transitional, Stack-tip downwash, Partial plume penetration
Dispersion	Puff plume element, PG /MP coefficients, rural mode, ISC building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration file including output species for SO_4, NO_3 and PM_{10}
Model Processing	Highest predicted 24-hour SO_4, NO_3 and PM_{10} concentrations for year
Background Values [a]	Ozone: 80 ppb; Ammonia: 10 ppb

[a] Recommended values by the Florida DEP.

Table B-3. CALMET Settings	
Parameter	Setting
Horizontal Grid Dimensions	250 by 280 km, 10 km grid resolution
Vertical Grid	9 layers
Weather Station Data Inputs	6 surface, 3 upper air, 14 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	MM4 data, 80 km resolution, 6 x 6 grid, used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

Table B-4.
Surface and Upper Air Stations Used in the CALPUFF Analysis

Station Name	Station Symbol	WBAN Number	UTM Coordinates Easting (km)	Northing (km)	Zone	Anemometer Height (m)
Surface Stations						
Tampa	TPA	12842	349.20	3094.25	17	6.7
Daytona Beach	DAB	12834	495.14	3228.05	17	9.1
Orlando	ORL	12815	468.96	3146.88	17	10.1
Gainesville	GNV	12816	377.40	3284.12	17	6.7
Vero Beach	VER	12843	557.52	3058.36	17	6.7
Fort Myers	FMY	12835	413.65	2940.38	17	6.1
Upper Air Stations						
Ruskin	TBW	12842	349.20	3094.28	17	NA
West Palm Beach	PBI	12844	587.87	2951.42	17	NA
Apalachicola	AQQ	12832	110.00[a]	3296.00	16	NA

[a] Equivalent coordinate for Zone 17; Zone 16 coordinate is 690.22 km.

Table B-5.
Hourly Precipitation Stations Used in the CALPUFF Analysis

Station Name (Florida)	Station Number	UTM Coordinates		
		Easting (km)	Northing (km)	Zone
Brooksville 7 SSW	81048	358.03	3149.55	17
Daytona Beach WSO AP	82158	495.14	3228.09	17
Deland 1 SSE	82229	470.78	3209.66	17
Inglis 3 E	84273	342.63	3211.65	17
Lakeland	84797	409.87	3099.18	17
Lisbon	85076	423.59	3193.26	17
Lynne	85237	409.26	3230.30	17
Orlando WSO McCoy	86628	468.99	3146.88	17
Parrish	86880	366.99	3054.39	17
Saint Leo	87851	376.48	3135.09	17
St. Petersburg	87886	339.04	3072.21	17
Tampa WSCMO AP	88788	349.17	3094.25	17
Venice	89176	357.59	2998.18	17
Venus	89184	466.756	2996.09	17

APPENDIX C

DATE : 11/25/98
TIME : 14:45:52
BPIP data for Hines2 HRSG

============================
BPIP PROCESSING INFORMATION:
============================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in METERS will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

UTMP is set to UTMN. The input is assumed to be in a local X-Y coordinate system as opposed to a UTM coordinate system. True North is in the positive Y direction.

Plant north is set to .00 degrees with respect to True North.

BPIP data for Hines2 HRSG

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
UNIT2	38.10	.00	61.00	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)
DATE : 11/25/98
TIME : 14:45:52

BPIP data for Hines2 HRSG

BPIP output is in meters

SO	BUILDHGT	UNIT2	24.40	24.40	24.40	24.40	24.40	24.40
SO	BUILDHGT	UNIT2	24.40	24.40	24.40	24.40	24.40	24.40
SO	BUILDHGT	UNIT2	24.40	24.40	24.40	24.40	24.40	24.40
SO	BUILDHGT	UNIT2	24.40	24.40	24.40	24.40	24.40	24.40
SO	BUILDHGT	UNIT2	24.40	24.40	24.40	24.40	24.40	24.40
SO	BUILDHGT	UNIT2	24.40	24.40	24.40	24.40	24.40	24.40
SO	BUILDWID	UNIT2	21.31	28.26	34.36	39.42	43.28	45.82
SO	BUILDWID	UNIT2	46.97	46.70	45.00	46.70	46.97	45.82
SO	BUILDWID	UNIT2	43.28	39.42	34.36	28.26	21.31	13.70
SO	BUILDWID	UNIT2	21.31	28.26	34.36	39.42	43.28	45.82
SO	BUILDWID	UNIT2	46.97	46.70	45.00	46.70	46.97	45.82
SO	BUILDWID	UNIT2	43.28	39.42	34.36	28.26	21.31	13.70

```
'BPIP data for Hines2 HRSG'
'ST'
'METERS' 1.00
'UTMN' 0.00
1
'A'  1 0.0
4 24.4
  0.000       0.000
  0.000      45.000
 13.700      45.000
 13.700       0.000
1
'UNIT2'  0.0   38.1       6.8        0.0
0
□
```

APPENDIX D

SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR POWER BLOCK 2 BY OPERATING LOAD AND AIR INLET TEMPERATURE

Table D-1. Maximum Pollutant Concentrations Predicted for One Combustion Turbine in Combined Cycle Operation Firing Natural Fuel and Distillate Fuel Oil Based on Modeled Generic Emission Rate

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature									Averaging	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)								
	Base Load			80% Load			60% (NG)/65% Load(FO)				Base Load			80% Load			60% (NG)/65% Load(FO)		
Pollutant	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)	Time	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)
Natural Gas																			
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.1230	0.1345	0.1447	0.1394	0.1571	0.1664	0.1924	0.2221	0.2411
										24-Hour	2.8408	3.2647	3.5763	3.4281	3.7110	4.0386	4.7151	5.0154	5.2864
										8-Hour	5.4888	6.1829	6.8437	6.5344	7.1025	7.7247	8.9840	9.5138	9.9823
										3-Hour	10.2027	11.4684	12.6709	12.1083	13.1413	14.2708	16.5516	17.5092	18.3551
										1-Hour	18.0695	19.8541	21.5114	20.7403	22.2096	23.9829	27.5210	28.9907	30.2814
SO_2	5.6	5.1	4.8	4.3	4.3	4.0	3.8	3.6	3.3	Annual	0.00873	0.00868	0.00870	0.00755	0.00850	0.00833	0.00914	0.01002	0.01001
										24-Hour	0.2015	0.2107	0.2151	0.1858	0.2008	0.2021	0.2239	0.2264	0.2195
										3-Hour	0.724	0.740	0.762	0.656	0.711	0.714	0.786	0.790	0.762
PM10	8.5	7.9	7.2	7.5	7.1	6.3	6.1	5.8	5.5	Annual	0.0131	0.0133	0.0131	0.0131	0.0140	0.0132	0.0147	0.0163	0.0166
										24-Hour	0.3029	0.3232	0.3237	0.3234	0.3313	0.3216	0.3611	0.3690	0.3650
NO_x	25.0	23.1	21.2	20.6	19.1	17.7	16.8	15.9	14.6	Annual	0.039	0.039	0.039	0.036	0.038	0.037	0.041	0.044	0.044
CO	46.0	42.0	37.0	38.0	35.0	33.0	154.0	146.0	134.0	8-Hour	3.18	3.27	3.19	3.13	3.13	3.21	17.43	17.50	16.85
										1-Hour	10.47	10.51	10.03	9.93	9.79	9.97	53.40	53.33	51.13
Distillate Fuel Oil																			
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0708	0.0741	0.0832	0.0717	0.0760	0.0858	0.0794	0.0837	0.0994
										24-Hour	1.7604	1.8592	2.2787	1.7810	1.9301	2.3802	2.1106	2.2985	2.5810
										8-Hour	3.3783	3.5957	4.3951	3.4208	3.7561	4.6183	4.0223	4.4388	5.0524
										3-Hour	6.2390	6.6994	8.2033	6.3266	7.0282	8.6132	7.5181	8.2835	9.4091
										1-Hour	11.7785	12.5418	14.8109	11.9646	13.0456	15.4148	13.7881	14.9296	16.5711
SO_2	105.6	97.1	86.0	85.6	79.4	71.0	72.0	68.0	62.0	Annual	0.094	0.091	0.090	0.077	0.076	0.077	0.072	0.072	0.078
										24-Hour	2.34	2.28	2.47	1.92	1.93	2.13	1.91	1.97	2.02
										3-Hour	8.30	8.20	8.89	6.82	7.03	7.71	6.82	7.10	7.35
PM10	64.8	59.6	52.5	52.4	48.6	44.3	43.5	40.9	37.2	Annual	0.0577	0.0557	0.0551	0.0473	0.0465	0.0479	0.0435	0.0432	0.0466
										24-Hour	1.437	1.397	1.507	1.175	1.181	1.330	1.156	1.185	1.210
NO_x	116.9	109.4	96.7	96.6	89.4	80.0	81.2	76.0	69.3	Annual	0.104	0.102	0.101	0.087	0.086	0.086	0.081	0.080	0.087
CO	112.0	106.0	91.0	111.0	103.0	89.0	101.0	94.0	86.0	8-Hour	4.77	4.80	5.04	4.78	4.87	5.18	5.12	5.26	5.47
										1-Hour	16.62	16.75	16.98	16.73	16.93	17.29	17.55	17.68	17.96

Note: NG= natural gas; FO= fuel oil

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

Table D-2. Maximum Pollutant Concentrations Predicted for Two Combined-Cycle Combustion Turbines Firing Natural Gas and Distillate Fuel Oil by Operating Load and Inlet Ambient Temperature

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)								
		Base Load			80% Load			60% (NG) /65% Load(FO)		
		20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)	20°F	59°F	90°F(NG)/ 105°F (FO)
Natural Gas										
SO_2	Annual	0.017	0.017	0.017	0.015	0.017	0.017	0.018	0.020	0.020
	24-Hour	0.403	0.421	0.430	0.372	0.402	0.404	0.448	0.453	0.439
	3-Hour	1.45	1.48	1.52	1.31	1.42	1.43	1.57	1.58	1.52
PM10	Annual	0.0262	0.0266	0.0262	0.0263	0.0281	0.0265	0.0295	0.0327	0.0333
	24-Hour	0.606	0.646	0.647	0.647	0.663	0.643	0.722	0.738	0.730
NO_x	Annual	0.078	0.078	0.077	0.072	0.076	0.074	0.081	0.089	0.089
CO	8-Hour	6.36	6.54	6.38	6.26	6.26	6.42	34.9	35.0	33.7
	1-Hour	20.9	21.0	20.1	19.9	19.6	19.9	107	107	102
Distillate Fuel Oil										
SO_2	Annual	0.188	0.181	0.180	0.155	0.152	0.154	0.144	0.143	0.155
	24-Hour	4.68	4.55	4.94	3.84	3.86	4.26	3.83	3.94	4.03
	3-Hour	16.6	16.4	17.8	13.6	14.1	15.4	13.6	14.2	14.7
PM10	Annual	0.115	0.111	0.110	0.0945	0.0930	0.0959	0.0870	0.0864	0.0932
	24-Hour	2.87	2.79	3.01	2.35	2.36	2.66	2.31	2.37	2.42
NO_x	Annual	0.21	0.20	0.20	0.17	0.17	0.17	0.16	0.16	0.17
CO	8-Hour	9.53	9.60	10.08	9.57	9.75	10.4	10.2	10.5	10.9
	1-Hour	33.2	33.5	34.0	33.5	33.9	34.6	35.1	35.4	35.9

Note: NG= natural gas; FO= fuel oil

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

Table D-3. Summary of Maximum Pollutant Concentrations Predicted for Two Combined-Cycle Combustion Turbines Compared to the EPA Class II Significant Impact Levels, PSD Class II Increments, and AAQS

Pollutant	Averaging Time	Maximum Concentration (ug/m3) Natural Gas	Fuel Oil	Natural Gas/ Fuel Oil Annual (1)	EPA Class II Significant Impact Levels (ug/m^3)	PSD Class II Increments (ug/m^3)	AAQS (ug/m^3)
SO_2	Annual	0.018	0.19	0.038	1	25	60
	24-Hour	0.45	4.9	NA	5	91	260
	3-Hour	1.6	17.8	NA	25	512	1,300
PM10	Annual	0.029	0.12	0.039	1	17	50
	24-Hour	0.72	3.0	NA	5	30	150
NO_x	Annual	0.081	0.21	0.096	1	25	100
CO	8-Hour	34.9	10.9	NA	500	NA	10,000
	1-Hour	107	35.9	NA	2,000	NA	40,000

NA= not applicable

(1) Based on firing natural gas and fuel oil for the following hours:

Natural gas	7,760 hours
Fuel Oil	1,000 hours
	8,760 hours

Table D-4. Maximum Pollutant Concentrations Predicted for One Combustion Turbine Firing Natural Fuel and Distillate Fuel Oil In Combined-Cycle Operation at the PSD Class I Area of the Chassahowitzka NWA Based on Modeled Generic Emission Rate

Pollutant	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature: Base Load 20°F	Base Load 59°F	Base Load 90°F(NG)/ 105°F (FO)	80% Load 20°F	80% Load 59°F	80% Load 90°F(NG)/ 105°F (FO)	60% (NG) /65% Load(FO) 20°F	60% (NG) /65% Load(FO) 59°F	60% (NG) /65% Load(FO) 90°F(NG)/ 105°F (FO)	Averaging Time	Maximum Predicted Concentrations (ug/m³) by Operating Load and Air Temperature (1): Base Load 20°F	Base Load 59°F	Base Load 90°F(NG)/ 105°F (FO)	80% Load 20°F	80% Load 59°F	80% Load 90°F(NG)/ 105°F (FO)	60% (NG) /65% Load(FO) 20°F	60% (NG) /65% Load(FO) 59°F	60% (NG) /65% Load(FO) 90°F(NG)/ 105°F (FO)
Natural Gas																			
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0077	0.0078	0.0080	0.0079	0.0080	0.0082	0.0085	0.0086	0.0088
										24-Hour	0.1025	0.1050	0.1072	0.1062	0.1081	0.1101	0.1139	0.1157	0.1173
										8-Hour	0.3670	0.3780	0.3879	0.3833	0.3917	0.4005	0.4173	0.4241	0.4299
										3-Hour	0.7339	0.7560	0.7758	0.7667	0.7834	0.8009	0.8346	0.8481	0.8598
										1-Hour	1.2786	1.3178	1.3532	1.3369	1.3666	1.3980	1.4580	1.4821	1.5030
SO_2	5.6	5.1	4.8	4.3	4.3	4.0	3.8	3.6	3.3	Annual	0.00055	0.00050	0.00048	0.00043	0.00043	0.00041	0.00040	0.00039	0.00036
										24-Hour	0.0073	0.0068	0.0064	0.0058	0.0059	0.0055	0.0054	0.0052	0.0049
										3-Hour	0.052	0.049	0.047	0.042	0.042	0.040	0.040	0.038	0.036
PM10	8.5	7.9	7.2	7.5	7.1	6.3	6.1	5.8	5.5	Annual	0.0008	0.0008	0.0007	0.0007	0.0007	0.0007	0.0007	0.0006	0.0006
										24-Hour	0.0109	0.0104	0.0097	0.0100	0.0097	0.0088	0.0087	0.0085	0.0081
NO_x	25.0	23.1	21.2	20.6	19.1	17.7	16.8	15.9	14.6	Annual	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Distillate Fuel Oil																			
Generic (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0064	0.0066	0.0068	0.0064	0.0066	0.0069	0.0067	0.0068	0.0070
										24-Hour	0.0840	0.0854	0.0894	0.0843	0.0863	0.0904	0.0876	0.0896	0.0924
										8-Hour	0.2845	0.2905	0.3025	0.2859	0.2943	0.3118	0.2999	0.3083	0.3200
										3-Hour	0.5689	0.5809	0.6150	0.5719	0.5887	0.6237	0.5999	0.6167	0.6401
										1-Hour	0.9890	1.0102	1.0705	0.9942	1.0239	1.0859	1.0438	1.0735	1.1150
SO_2	105.6	97.1	86.0	85.6	79.4	71.0	72.0	68.0	62.0	Annual	0.009	0.008	0.007	0.007	0.007	0.006	0.006	0.006	0.005
										24-Hour	0.11	0.10	0.10	0.09	0.09	0.08	0.08	0.08	0.07
										3-Hour	0.76	0.71	0.67	0.62	0.59	0.56	0.54	0.53	0.50
PM10	64.8	59.6	52.5	52.4	48.6	44.3	43.5	40.9	37.2	Annual	0.0052	0.0049	0.0045	0.0042	0.0041	0.0038	0.0037	0.0035	0.0033
										24-Hour	0.069	0.064	0.059	0.056	0.053	0.051	0.048	0.046	0.043
NO_x	116.9	109.4	96.7	96.6	89.4	80.0	81.2	76.0	69.3	Annual	0.009	0.009	0.008	0.008	0.007	0.007	0.007	0.007	0.006

Note: NG= natural gas; FO= fuel oil

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

Table D-5. Maximum Pollutant Concentrations Predicted for Two Combined-Cycle Combustion Turbines Firing Natural Gas and Distillate Fuel Oil by Operating Load and Inlet Ambient Temperature at the PSD Class I Area of the Chassahowitzka NWA

Pollutant	Averaging Time	Base Load 20°F	Base Load 59°F	Base Load 90°F(NG)/ 105°F (FO)	80% Load 20°F	80% Load 59°F	80% Load 90°F(NG)/ 105°F (FO)	60% (NG) /65% Load(FO) 20°F	60% (NG) /65% Load(FO) 59°F	60% (NG) /65% Load(FO) 90°F(NG)/ 105°F (FO)
		Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Temperature (1)								
Natural Gas										
SO_2	Annual	0.0011	0.0010	0.0010	0.0009	0.0009	0.0008	0.0008	0.0008	0.0007
	24-Hour	0.0145	0.0135	0.0129	0.0115	0.0117	0.0110	0.0108	0.0104	0.0097
	3-Hour	0.104	0.0976	0.0933	0.0831	0.0848	0.0802	0.0793	0.0766	0.0714
PM10	Annual	0.0016	0.0015	0.0014	0.0015	0.0014	0.0013	0.0013	0.0013	0.0012
	24-Hour	0.0218	0.0208	0.0194	0.0200	0.0193	0.0175	0.0174	0.0170	0.0162
NO_x	Annual	0.0049	0.0046	0.0043	0.0041	0.0039	0.0037	0.0036	0.0034	0.0032
Distillate Fuel Oil										
SO_2	Annual	0.0171	0.0160	0.0148	0.0139	0.0133	0.0123	0.0122	0.0117	0.0110
	24-Hour	0.223	0.209	0.194	0.182	0.173	0.162	0.159	0.153	0.144
	3-Hour	1.51	1.42	1.33	1.23	1.18	1.12	1.09	1.06	1.000
PM10	Annual	0.010	0.010	0.009	0.008	0.008	0.008	0.007	0.007	0.007
	24-Hour	0.137	0.128	0.118	0.111	0.106	0.101	0.096	0.092	0.087
NO_x	Annual	0.019	0.018	0.017	0.016	0.015	0.014	0.014	0.013	0.012

Note: NG= natural gas; FO= fuel oil

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

Table D-6. Summary of Maximum Pollutant Concentrations Predicted for Two Combined-Cycle Combustion Turbines Compared to the EPA Class I Significant Impact Levels and PSD Class I Increments

Pollutant	Averaging Time	Maximum Concentration (ug/m3) Natural Gas	Distillate Fuel Oil	Natural Gas/ Fuel Oil Annual (1)	EPA Class I Significant Impact Levels (ug/m^3)	PSD Class I Increments (ug/m^3)
ISCST						
SO_2	Annual	0.0011	0.017	0.0029	0.1	2
	24-Hour	0.015	0.22	NA	0.2	5
	3-Hour	0.104	1.51	NA	1.0	25
PM10	Annual	0.0016	0.010	0.0026	0.2	4
	24-Hour	0.022	0.137	NA	0.3	8
NO_x	Annual	0.005	0.019	NA	0.1	2.5
CALPUFF						
SO_2	Annual	0.00040	0.0081	0.0013	0.1	2
	24-Hour	0.0090	0.17	NA	0.2	5
	3-Hour	0.023	0.45	NA	1.0	25
PM10	Annual	0.00085	0.0065	0.0015	0.2	4
	24-Hour	0.016	0.124	NA	0.3	8
NO_x	Annual	0.00064	0.003	0.00094	0.1	2.5

NA= not applicable

(1) Based on firing natural gas and fuel oil for the following hours:

Natural gas	7,760 hours
Fuel Oil	1,000 hours
	8,760 hours