Florida Department of
Environmental Protection

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Secretary

November 22, 1993

Mr. Christian M. Hoberg
Environmental Policy Section
Federal Activities Branch
U.S. Environmental Protection Agency
Region IV
345 Courtland Street, NE
Atlanta, GA 30365

RE: Transmittal of the Draft BACT Determination, Conditions for Site Certification and Ambient Air Quality Analysis for the TECO/Polk Power Station

Dear Mr. Hoberg:

As requested in your telephone call of November 3, 1993, a draft copy of the TECO/Polk Power Station BACT determination, air conditions to be included in the site certification and ambient air quality analysis are forwarded for use in evaluation of the Environmental Impact Statement. Department comments, requested in your FAX of November 4, 1993, regarding the Air Quality Related Values Analysis in the Fish and Wildlife Service letter of July 26, 1993, will be provided separately within the next several weeks.

Please contact Doug Outlaw, 904/488-1344, BACT/LAER Coordinator or Tom Rogers, 904/488-0114, Environmental Administrator for Air Modeling Assessment, directly if you have any questions.

Sincerely,

G. Preston Lewis, P.E.
Division of Air Resources
Management

GPL/DO/bjb

Attachments

cc: Buck Oven
Tom Rogers

CURRENT 11/17/93

8. Best Available Control Technology

The applicant is proposing to construct, in phases, a 1,150 MW power plant in Polk County. The proposed facilities will be known as the Tampa Electric Company Polk Power Station. The first phase will consist of a nominal 150 MW combustion turbine (CT), initially fueled with No. 2 fuel oil and will serve as a peaking unit for a maximum of 10 percent capacity factor during its first year of operation. After a year, it will be converted to an Integrated Coal Gasification Combined Cycle (IGCC) unit with heat recovery steam generator (HRSG) and steam turbine (ST) for a nominal net 260 MW IGCC unit. After conversion, the coal-fueled advanced CT will be capable of baseload operations (i.e., 100 percent capacity factor) on syngas, while retaining the option to fire fuel oil as backup (maximum 10 percent capacity factor). Units proposed to be added at Polk Power Station include two combined cycle (CC) units totaling 440 MW (nominal) and six simple cycle (SC) CTs totaling 450 MW (nominal). All of these units will be fired with natural gas as the primary fuel and No. 2 fuel oil as backup. The phased schedule for construction and operation of the proposed generating units at the Polk Power Station is presented in Table 1.

Table 1

Proposed Schedule for Construction and Operation of Generating Units for ultimate capacity at the Polk Power Station Site

Activity/Unit	Start Construction	Completion/ In-Service
150/190-MW advanced CT[a]	January 1994[b]	July 1995
CG & HRSG/ST for 260-MW IGCC unit	January 1994[b]	July 1996
75-MW CT	April 1998	January 1999
75-MW CT	April 1999	January 2000
HRSG/ST for conversion of two 75-MW CTs for 220-MW CC unit	April 2000	January 2001
75-MW CT	April 2001	January 2002
220-MW CC	April 2001	January 2003
75-MW CT	April 2005	January 2006
75-MW CT	April 2006	January 2007
75-MW CT	April 2007	January 2008
75-MW CT	April 2008	January 2009
75-MW CT	April 2009	January 2010

a - 150 MW when operated in simple-cycle CT or CC mode and fired on fuel oil.
b - Construction activities may be initiated prior to this date if all applicable regulatory permits are obtained prior to December 1993.

The IGCC unit will be supported in part through funding from the U.S. Department of Energy (DOE) under the Clean Coal Technology Demonstration Program. Under the program, the IGCC unit will be used to demonstrate the integration of coal gasification (CG) and CC technologies and to demonstrate a more efficient method for removal of sulfur from syngas. The new cleanup technology is called hot gas clean up (HGCU). Conventional methods for sulfur removal for IGCC units require that the gas be cooled prior to cleaning, called cold gas cleanup (CGCU), and then reheated. By comparison, the HGCU technology efficiently cleans the gas at high temperatures, thereby increasing the overall plant efficiency. Under the agreement with DOE, Tampa Electric Company will demonstrate the HGCU system for a 2-year period.

The maximum tonnage of regulated air pollutants emitted from the proposed facility based on a 100 percent capacity factor and 8,760 hours per year are shown in Table 2. A simplified flow chart for the operation of the IGCC systems at the site is attached (Figures 1 - 3).

Table 2

Projected Maximum Annual Emissions (tpy)
for ultimate site capacity

Pollutant	IGCC[a] +	CC[b] +	SC[c] =	Total	Significance Rate (tpy)
PM (TSP)	399	260	246	905	25
PM (PM_{10})	399	260	246	905	15
SO_2	2469	720	654	3843	40
NO_x	2923	1308	1014	5245	40
CO	453	1092	978	2523	100
VOC	45	180	168	393	40
Pb	0.15	0.28	0.17	0.6	0.6
H_2SO_4	241	80	72	393	7
Fluorides	0.92	0.17	0.10	1.2	3
Hg	0.12	0.21	0.19	0.5	0.1
Be	0.007	0.013	0.008	0.03	0.0004
Total reduced sulfur (including H_2S)	6.2	0	0	6.2	10

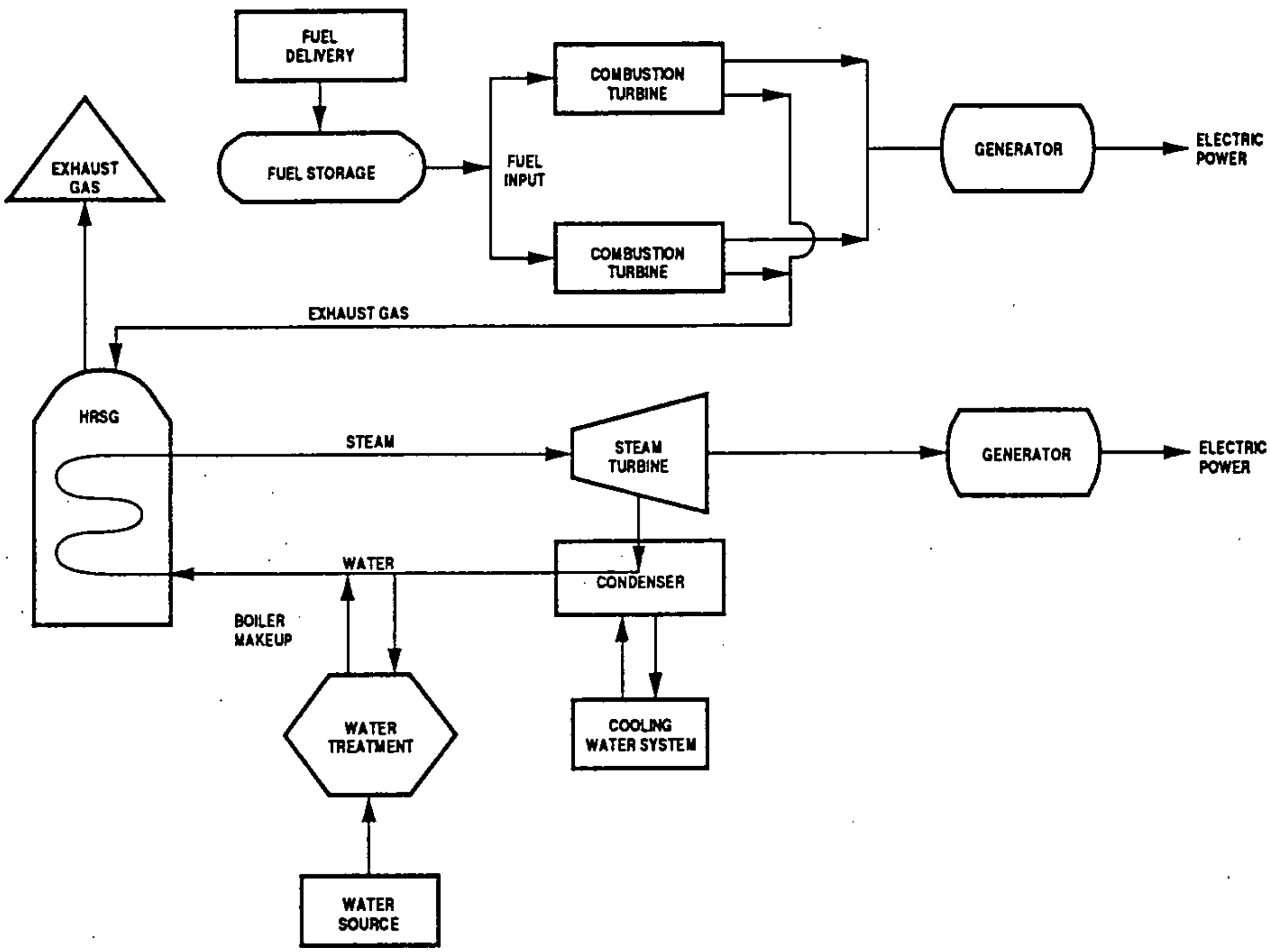

FIGURE 1.5.2-1.

SIMPLIFIED FLOW DIAGRAM OF COMBINED CYCLE POWER SYSTEM

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

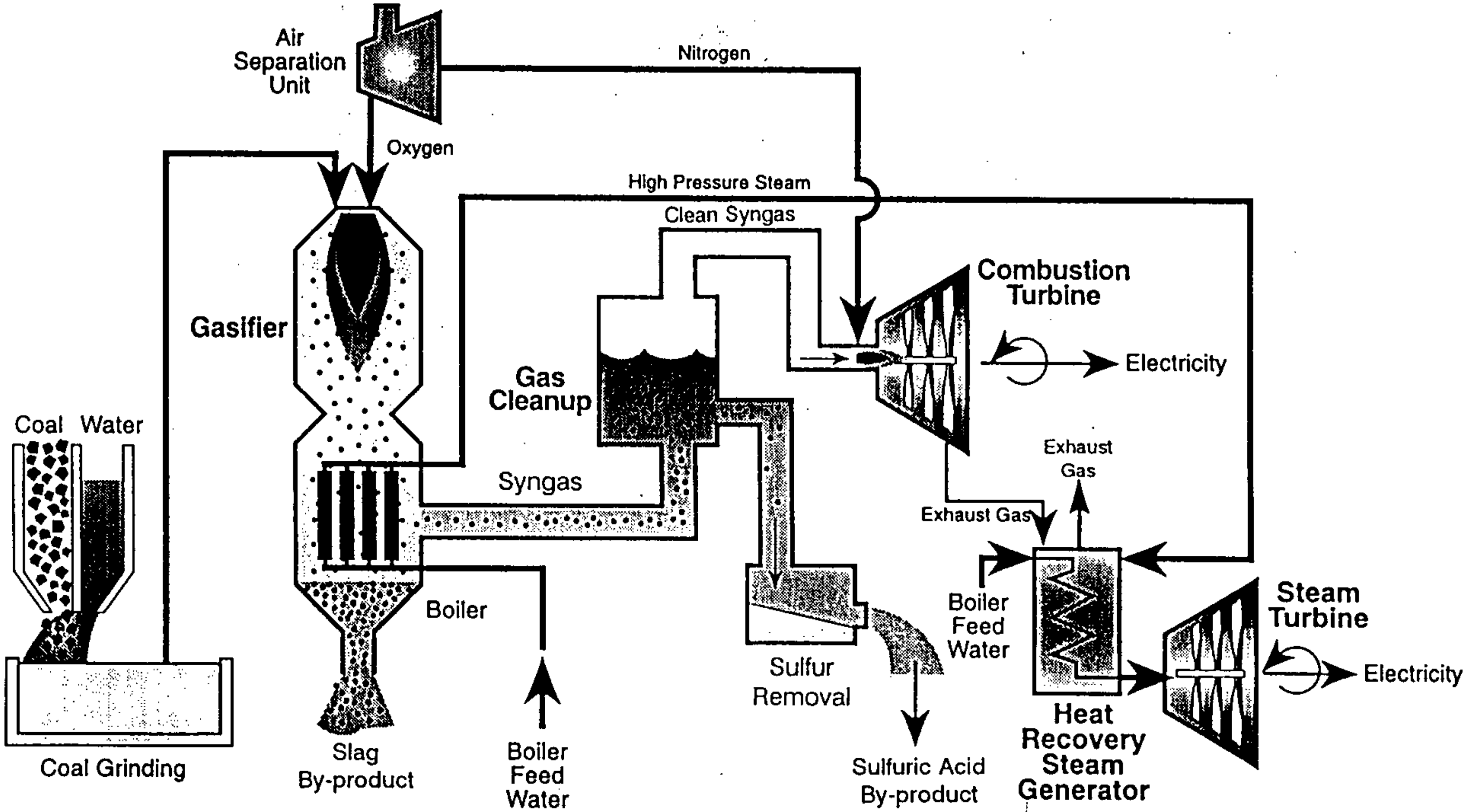

FIGURE 1.5.3-1.

SIMPLIFIED FLOW DIAGRAM OF INTEGRATED COAL GASIFICATION COMBINED CYCLE UNIT

Source: Texaco, 1992. Tampa Electric Company, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

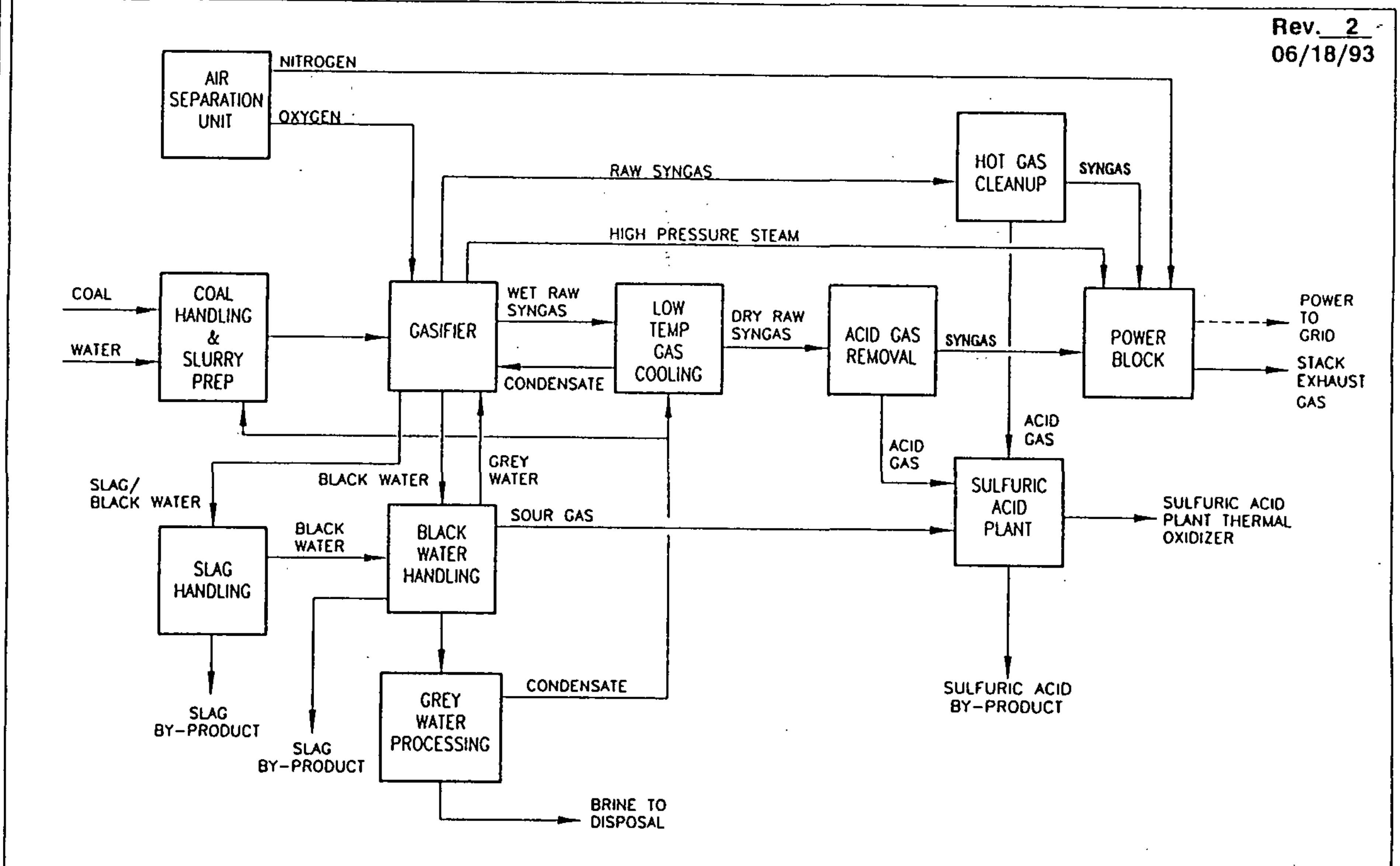

FIGURE 2-2.

GENERALIZED FLOW DIAGRAM OF IGCC SYSTEMS AND PROCESS

Source: ECT, 1993.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

a - IGCC emissions include the highest annual emissions estimates from the 7F CT (based on the larger of 100 percent CGCU or 50/50 CGCU/HGCU), plus related combustion emissions (e.g., thermal oxidizer), plus other associated process and fugitive emissions (PM, CO, VOC, and H_2S).

b - CC emissions represent the totals for four stand-alone CTs in CC mode.

c - SC emission represent the totals for six stand-alone CTs in simple cycle mode.

The proposed facility will also include one 49.5 MMBtu/hr auxiliary boiler fired with low sulfur (0.05% or less by weight) distillate fuel oil. The auxiliary boiler will operate only during startup and shutdown of the IGCC unit, or when steam from the IGCC unit's HRSG is unavailable. The auxiliary boiler will operate a maximum of 1,000 hours per year.

The coal gasification facility will serve as a source of medium Btu, low sulfur (0.07% or less, by weight, sulfur bearing compounds) coal-derived gas. The coal used in the gasification facility will have a maximum sulfur content of 3.05% and have a minimum heating value of approximately 11,035 Btu/lb. The coal gasification plant will consist of coal receiving, storage and process facilities, air separation unit, gasifier, product gas cleaning facilities, acid gas removal unit, and auxiliary equipment. The coal gasification unit will have two stacks, one flare stack used during startup, shutdown and emergency conditions and one thermal oxidation unit stack which will be used continuously.

The applicant has indicated the maximum tonnage of regulated air pollutants emitted from the IGCC unit CT during the initial phase, demonstration and post demonstration periods to be as shown in Table 3.

Table 3

Maximum Annual Emissions from IGCC Unit for Various Operating Configurations

Pollutant	Initial Year (tpy)[a]	Demonstration Period (tpy)[b]	Post-Demonstration Period (tpy)[c]
PM	20.1	315	315
SO_2	49.1	2,269	2,269
NO_x	164.7	2,908	1,044
CO	86.7	434	429
VOC	28.0	39.8	39.8

H_2SO_4	5.1	241	241
Pb	0.053	0.14	0.067
Fluorides	0.033	0.92	0.92
Hg	0.0031	0.11	0.017
Be	0.0025	0.0029	0.0029

a - Based on 10 percent maximum annual capacity factor firing fuel oil in simple cycle mode.
b - Based on baseload operations firing syngas, with a maximum of 8,760 hr/yr utilization of HGCU and up to 10 percent annual capacity factor firing fuel oil.
c - Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

Florida Administrative Code Rule 17-212.400 requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in Table 1.

Date of Receipt of A BACT Application

September 21, 1992

BACT Determination Requested by the Applicant

Combined Cycle Units

Pollutant	Determination
NO_X	9 ppmvd (NG) 25 ppmvd (Syngas firing) 42 ppmvd (No. 2 fuel oil firing)
SO_2	Firing of NG or Syngas Fuel oil with a maximum sulfur content of 0.05 % by weight, 0.048 lb/MMBtu
CO	Combustion control 25 ppmvd (NG) 30 ppmvd (No. 2 fuel oil firing) 25 ppmvd (Syngas firing)
VOC	Combustion control 7 ppmvd (NG) 7 ppmvd (No. 2 fuel oil firing) 1 ppmvd (Syngas firing)

Particulates	Good combustion, and type of fuels fired
Pb	Good combustion, and type of fuels fired
H_2SO_4	Firing of NG, Syngas and No. 2 fuel oil
Be	Firing of NG, Syngas and No. 2 fuel oil
AS	Firing of NG, Syngas and No. 2 fuel oil

Coal Gasification Plant

Raw Product Gas

Pollutant	Control Technology
Sulfur	Acid Gas Removal (95.6%)
Particulates	Water scrubbing

The raw product gas is fired in the combined cycle combustion turbine units and emissions of product gas are included in the BACT determination for those units.

CG Emission (Thermal Oxidizer)

Pollutant	Control Technology
SO_2	Fuel oil firing with a sulfur content not to exceed 0.05% by weight. (45.3 lb/hr)
NO_x	Combustion controls
CO	Combustion controls
Pb	Efficient Operation
H_2SO_4	Efficient Operation
Mercury	Efficient Operation
Beryllium	Efficient Operation
Inorganic Arsenic	Efficient Operation

Materials Handling and Storage

Fugitive Dust Source	Control Technology
Coal Unloading	Enclosed - including a Collection System
Conveyers and Transfer Points (Coal, Slag)	Transfer points enclosed with Collection System. Conveyers enclosed

Coal Storage and Reclaiming	Crusting Agent Application Wet Suppression Systems or Crusting Agents Surfactant Application[1]
Fuel Oil Storage	Bottom Loaded/Submerged Filling
	Auxiliary Boiler
NO_x	Low NOx Burners and Combustion Controls, limited operation[2] (0.159 lb/MMBtu)
SO_2	Fuel oil firing with a sulfur content not to exceed 0.05 % by weight, and limited operation (0.053 lb/MMBtu)
CO	Combustion Controls (0.087 lb/MMBtu)
VOC	Combustion Controls (0.0485 lb/MMBtu)
Particulates	Combustion Controls (0.061 lb/MMBtu)
Pb	Combustion Controls
Mercury	Combustion Controls
Beryllium	Combustion Controls
Inorganic Arsenic	Combustion Controls

1 - Total Coal Handling Sources PM Emissions are 10.7 tpy
2 - Maximum of 1000 hours of operation per year

Annual pollutant emissions are shown in Table 1 for all sources. Pollutant emission rates are listed in the section entitled "BACT Determination by DEP".

Flare Stacks

This source did not propose a BACT since its operation is expected to be infrequent (startup and shutdown, and emergencies).

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-296, Stationary Sources - Emission Standards, this BACT determination is 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. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from combined cycle power plants and coal fired power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- Combustion Products (Particulates and Heavy Metals). Controlled generally by good combustion of clean fuels and/or fabric filters.
- Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.
- Acid Gases (SOx, NOx, HCL, Fl). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc.), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

Combustion Products

The IGCC facility's projected emissions for combustion products (Particulate Matter (PM) and trace heavy metals) exceed the significant emission rates given in Florida Administrative Code Rule 17-212.410, Table 212.400-2. A review of the BACT/LAER Clearinghouse indicates that the proposed PM/PM_{10} emission level of 0.037 lbs/MMBtu for syngas for the IGCC unit exceeds the particulate limit for recent determinations of coal fired boiler. The applicant proposed PM/PM_{10} emission level of 0.014 lbs/MMBtu for No. 2 oil firing for the IGCC unit is consistent with previous BACT determinations in Florida.

In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium, mercury and arsenic from turbines. BACT for heavy metals is typically represented by the level of particulate control. The emission factors for PM/PM_{10} when firing the IGCC with syngas and No. 2 fuel oil are judged to represent BACT for beryllium, arsenic and mercury.

PM/PM_{10} emissions are controlled for the auxiliary boiler by firing with No. 2 fuel oil with a sulfur concentration not to exceed 0.05%, by weight. This fuel sulfur level is consistent with recent BACT determinations for similar facilities.

Products of Incomplete Combustion

The emissions of carbon monoxide, volatile organic compounds and other organics from combustion turbines are largely dependent upon the completeness of combustion and the type of fuel used. The applicant has indicated that the carbon monoxide emissions from the proposed turbines are based on exhaust concentrations of 25 ppmvd for syngas and 30 ppmvd for No. 2 fuel oil. Volatile organic compound emissions have been based on exhaust concentrations of 7, 1 ppmvd for fuel oil firing, and syngas, respectively.

A review of the BACT/LAER clearinghouse indicates that several of the largest combustion turbines (those with heat inputs greater that 1,000 MMBtu/hour) have been permitted with CO limitations which are similar to those proposed by the applicant. For VOC, the clearinghouse also indicates that the proposed emissions are consistent with that established for other turbines of similar size, thereby suggesting that the proposed emission levels for both CO and VOC are reasonable. Although the majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, additional control is achievable through the use of catalytic oxidation.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection for NO_X control. These installations have been required to utilize LAER technology, and typically have CO limits in the 10 ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, thereby reducing the amount of thermal energy required compared to thermal oxidation. For CC combustion turbines, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature and desired efficiency. Most gas turbine applications have been limited to smaller cogeneration facilities burning natural gas in nonattainment areas.

The application of oxidation catalyst is not being required as BACT for the IGCC unit due to high content of sulfur in the fuel. Syngas fuel which will be utilized at 100 percent capacity factor contains up to 0.07% by weight sulfur content. These sulfur compounds are oxidized to SO_2 in the combustion process and will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Therefore, the use of an oxidation catalyst system for the IGCC unit is not BACT due to corrosion problems.

Acid Gases - Sulfur Dioxide

The emissions of sulfur dioxide, nitrogen oxides, fluorides, and sulfuric acid mist, as well as other acid gases which are not "regulated" under the PSD Rule, represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. Sulfur dioxide emissions from combustion turbines are directly related to the sulfur content of the fuel being combusted.

The IGCC facility's projected emissions for SO_2 exceed the significant emission rates given in Florida Administrative Code Rule 17-212.410, Table 212.400-2. A review of the BACT/LAER Clearinghouse indicates that the proposed SO_2 emission level of 0.247 lbs/MMBtu for syngas exceeds the SO_2 limit for recent determinations of coal fired boilers.

For the IGCC combustion turbine, the applicant has proposed the use of Syngas, No. 2 fuel oil with a maximum sulfur content of 0.05%, by weight, and coal gasification to control sulfur dioxide emissions. In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content syngas and fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emissions from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later on in the preamble, they stated that "FGD... would cost about two to three times as much as the gas turbine." The economic impact of applying FGD today would be no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

Coal gasification sulfur content is controlled through fuel-production process controls. Sulfur removal stages in the coal gasification process include acid gas removal, and sulfuric acid plant thermal oxidizer. Acid gas removal systems remove hydrogen sulfide, carbonyl sulfide and carbon dioxide from the fuel gas using an acid gas absorbent solution. The acid gases are stripped from the adsorbent solution and sent to the sulfuric acid plant for introduction into a thermal oxidizer, where the remaining sulfur compounds are converted to SO_2, and finally converted to commercial grade liquid H_2SO_4. The overall sulfur removal efficiency is 95.6%. The sulfur bearing compounds content of the syngas is reduced to 0.07% by weight, or less.

The elimination of flue gas control as a BACT option then leaves the use of NG, CG with the sulfur removal process or low sulfur coal as the options to be investigated. The applicant has proposed the use of syngas, CG with sulfur removal or No. 2 fuel oil (maximum of 876 hours per year per IGCC combustion turbine) with a maximum sulfur content of 0.05%, by weight, as BACT for this project.

Although the applicant's proposed coal gasification acid gas cleanup process is an existing technology, development is continuing on coal gasification systems. The data base to determine whether the proposed sulfur bearing compounds level of 0.07% by weight is reasonable for a coal gasification facility with resulting proposed emissions of 0.247 lbs/MMBtu is limited. A commercial scale demonstration of an IGCC 100 MW power plant has been conducted adjacent to Southern California Edison's Cool Water generating station. During the Cool Water demonstration project, high sulfur coals, Illinois #6 and Pittsburgh #8, with a sulfur content of about 3.1 percent were tested. The SO_2 emission rate was 0.11 lbs/MMBtu for the Pittsburgh #8 coal and was even lower for the Illinois #6 coal (Technical Brief, Cool Water Coal Gasification Program: Commercial Scale Demonstration of IGCC Technology Completed, Electric Power Research Institute). The Polk Power Station IGCC unit has been designed for a larger capacity and is expected to be capable of using coals from various sources not included in the Cool Water demonstration project tests. Although, emission rates from the Cool Water tests are representative of the SO_2 emission range that can be achieved using IGCC units, the study was conducted as a demonstration project and the unit was later converted to another fuel source.

The Polk Power Station IGCC coal gasification system includes an option for both cold gas and hot gas cleanup and emissions from the Cool Water demonstration project are not directly comparable to the hot gas cleanup system. However, an objective of the hot gas cleanup system test is to demonstrate the efficiency in decreasing sulfur emissions compared to cold gas cleanup system.

Acid Gases - Nitrogen Oxides

The applicant has stated that BACT for nitrogen oxides for the IGCC unit will be met by using nitrogen diluent injection to limit emissions to 25 ppmvd at 15% oxygen when burning syngas, and water injection to achieve 42 ppmvd at 15% oxygen when burning No. 2 fuel oil. The emission limit of 25 ppmvd when burning syngas is higher compared to 9 ppmvd when burning NG in a combustion turbine due to the difference in composition and heat content between the two fuels. In contrast to natural gas which is predominately methane, syngas is composed of a variety of constituents including CO, hydrogen, CO_2, nitrogen, and water. The combustible components of syngas are primarily CO and hydrogen instead of methane. CO and hydrogen burn at a higher adiabatic flame temperature than methane and therefore can produce approximately three times as much NO_x as natural gas.

A review of EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15 percent oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system. The two 25 MW combustion turbines are located in Kern County, California and the degree of control at this facility exceeds BACT requirements.

Selective catalytic reduction 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 applicant has indicated that the cost effectiveness for the application of SCR technology to the Polk Power Station IGCC project was determined to be $6,272 per ton of NO_x removed for a 50% reduction of NO_x concentration from 25 ppmvd to 12.5 ppmvd. The cost impact analysis was conducted using the OAQPS factors and project-specific economic factors. An assessment of economics impacts was performed by comparing control costs between a baseline case of advanced combustion and nitrogen injection and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve NO_x exhaust concentrations of 25 and 42 ppmvd at 15% oxygen for syngas and oil-firing, respectively. Based on Japanese experience, SCR technology was premised to achieve NO_x concentration of 12.5 and 21 ppmvd at 15% oxygen for syngas and oil-firing, respectively, representing a 50% NO_x removal efficiency.

Since SCR has been determined to be BACT for several combined cycle facilities firing natural gas, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics. In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products Inc.), the following statement is made:

"In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

The auxiliary boiler is expected to operate 1,000 hours per year or less. The applicant is proposing to control SO_2 and acid gas emissions by firing with No. 2 fuel oil with a sulfur content of 0.05% or less, by weight, and by using combustion controls. Therefore, limited operation and low sulfur distillate oil represents BACT for the auxiliary boiler.

H_2SO_4 Plant Thermal Oxidizer

The predominant emission from the thermal oxidizer is sulfur dioxide. The sulfur dioxide emissions proposed for the facility are based on the highest removal efficiency that is now being maintained at other coal gasification facilities. This is accomplished by using an acid gas removal system followed by a sulfuric plant thermal oxidizer. This process is capable of providing an overall sulfur removal rate of 95.6 percent.

Fugitive Sources

The applicant has indicated that fugitive particulate emissions may result from the storage and handling of coal, slag, and sulfur. BACT for controlling these activities is good engineering design and practices. Control measures shall include the following:

- Minimize number of material transfer points
- Apply crusting agent application to inactive storage areas
- Enclose conveyers and transfer points
- Provide induced collection systems for dust
- Provide wet suppression systems (surfactant)
- Cover by-product storage areas (upon completion of cell)
- Handle and store sulfur in a molten or continuous crystalline state

A review of the control strategy indicates that the applicant has proposed taking all reasonable measures to minimize fugitive particulate emissions.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NO_x control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NO_x control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Although the use of SCR does have some environmental impacts, the disadvantages do not outweigh the benefit which would be provided by reducing nitrogen oxide emissions by 50 percent. The benefits of NO_x control by using SCR is substantiated by the fact that a number of BACT determinations have established SCR as the control measure for nitrogen oxides over the last five years for combustion turbines.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of syngas and No. 2 fuel oil have been evaluated. Beryllium and Mercury exceeds the PSD significant level. Other toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than one ton per year.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense for firing with natural gas or fuel oil. Therefore, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of syngas or No. 2 fuel oil.

Potentially Sensitive Concerns

With regard to controlling NOx emissions from SCR the applicant has expressed concerns regarding SCR catalyst deactivation due to poisoning, oxidation of SO2 to SO3, formation of H2SO4, formation of ammonium bisulfate and ammonium sulfate, risk due to potential leaks from storage of NH3 and disposal of spent catalyst which may be considered hazardous.

A review of permitting activities for combined cycle proposals across the nation indicates that SCR has been required or proposed for installations with a variety of operating conditions including firing with fuel oil. SCR also has been accepted as BACT for boilers fired with pulverized coal. Although the concerns expressed by the applicant were valid at one time, the most recent experiences indicate that these problems have been resolved through advances in catalysts and experiences gained in operation.

BACT Determination by DEP

1. Combustion Products - PM/PM_{10}

During the two year demonstration period for the IGCC unit at the Polk Power Station, the applicant's proposed PM/PM10 emission limit of 0.037 lb/MMBtu is accepted for IGCC hot cleanup testing conducted under the Cooperative agreement with the US DOE.

For IGCC operation following the 2-year demonstration period the PM/PM_{10} emission limit of 0.037 lbs/MMBtu is high compared to Indiantown cogeneration facility emission limit of 0.018 lbs/MMBtu. Since the proposed emission levels exceeds recent BACT determinations for similar facilities, particulate emissions control for the IGCC unit will be limited to 0.018 lb/MMBtu.

2. Products of Incomplete Combustion - CO and VOC

The use of an oxidation catalyst system for the IGCC system is not found to be BACT due to the high sulfur content in the syngas and resulting corrosion problems. Emissions are to be controlled by good combustion practices during demonstration and post demonstration periods.

3. Acid Gases - Sulfur Dioxides

During the 2-year demonstration period for the IGCC unit at the Polk Power Station, the applicant's proposed SO_2 emissions limit of 0.247 lbs/MMBtu is accepted for IGCC demonstration testing conducted under the Cooperative Agreement with the US DOE. The proposed emissions limit will allow for testing of coals with a broad range of sulfur content and for evaluation of the IGCC unit design.

For IGCC operations following the demonstration period, estimates for the incremental increase in cost for use of low sulfur coals for syngas product can be justified. Therefore, SO_2 emissions following the demonstration period shall not exceed the 0.17 lbs/MMBtu limit established in a recent BACT determination for the Indiantown Cogeneration facility. The 0.17 lbs/MMBtu limit shall apply during the 2-year demonstration period to any IGCC unit operations not conducted as a part of the demonstration requirements of the US DOE cooperative agreement.

The SO_2 emissions shall be limited to 0.17 lbs/MMBtu for the IGCC unit by the use of low sulfur coal.

Acid Gases - Nitrogen Oxides

The annualized cost per ton for NO_x removal of $6,272 for the IGCC SCR estimated by the applicant exceeds recent estimates for other applications. Recent published estimates for a pulverized coal plant (Selective Catalytic Reduction for a 460 MW coal fueled unit: Overview of a NO_x Reduction System Selection, EPRI, 1993) with a NO_x reduction of 47 percent was $3,265 per ton in 1997 dollars. Costs per ton in this range indicate SCR is a reasonable alternative. Therefore, the IGCC NO_x emission limit is 12.5 ppmvd during the demonstration and post demonstration periods, and that SCR shall be used to meet 12.5 ppmvd NO_x emission limit.

The emission limits for the IGCC unit for firing with syngas and No. 2 fuel oil for the Polk Power Station are thereby established as follows:

Pollutant		Emission Limitations						
			IGCC Post Demonstration			IGCC 2-year Demonstration		
	Fuel	Basis	lb/hr	tpy[a]	Fuel	Basis	lb/hr	tpy[b]
NO_x	Oil	42 ppmvd			Oil	42 ppmvd		
	Syngas	12.5 ppmvd	111.25	522	Syngas	12.5 ppmvd	111.25	522
VOC[c]	Oil	0.0090 lb/MMBtu			Oil	0.0090 lb/MMBtu		
	Syngas	0.0017 lb/MMBtu	3	39.8	Syngas	0.0017 lb/MMBtu	3	39.8
CO	Oil	30 ppmvd			Oil	30 ppmvd		
	Syngas	25 ppmvd	98	429	Syngas	25 ppmvd	99	434
PM/PM_{10}	Oil	0.014 lb/MMBtu			Oil	0.014 lb/MMBtu		
	Syngas	0.018 lb/MMBtu	35	153	Syngas	0.037 lb/MMBtu	72	315
Pb	Oil	3.09E-5 lb/MMBtu			Oil	3.09E-5 lb/MMBtu		
	Syngas	1.98E-6 lb/MMBtu	0.0035	0.067	Syngas	1.98E-6 lb/MMBtu	0.0035	0.067
SO_2	Oil[d]	0.047 lb/MMBtu			Oil	0.047 lb/MMBtu		
	Syngas	0.17 lb/MMBtu	373	1634	Syngas	0.247 lb/MMBtu	518	2269

NOTES: a - Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

b - Based on baseload operations firing syngas, with a maximum of 8760 hrs/yr utilization of HGCU operations; up to 10 percent annual capacity factor firing fuel oil.

c - Exclusive of background concentrations.

d - Sulfur dioxide emissions based on a maximum of 0.05 percent sulfur, by weight.

Auxiliary Boiler

For the auxiliary boiler, BACT will be represented by a limitation on hours of operation and the use of clean fuel (maximum 1,000 hours per year firing No. 2 fuel oil with 0.05% sulfur, by weight).

H_2SO_4 Plant Thermal Oxidizer

A review of the proposed emission rates for the thermal oxidizer indicates that equipment in and of itself represents BACT for these sources.

Fugitive Sources

A review of the control strategy indicates that the applicant has proposed taking all reasonable measures to minimize fugitive particulate emissions and is representative of BACT.

Florida Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

November 5, 1993

Mr. Thomas W. Davis, P.E.
Environmental Consulting & Technology, Inc.
3701 N.W. 98th. St.
Gainesville, FL 32606

RE: Tampa Electric Company
Polk Power Station
Conditions of Certification

Dear Mr. Davis:

This is a follow-up to our letter of October 19, 1993, in which we outlined recommended changes to the Conditions of Certification in response to your request of the October 14, 1993 letter. We will recommend additional changes to the conditions of certification as follows:

The heat input language (Specific condition B) in the Condition of Certification will be changed to read as follows:

> "The maximum heat input to the IGCC combustion turbine (CT) shall neither exceed 1,755 MMBtu/hr while firing syngas, nor 1765 MMBtu/hr while firing No. 2 fuel oil at an ambient temperature of 59° F. Heat input may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves for the heat input correction to other temperatures shall be provided to DEP for review 90 days after the selection of the CT. Subject to approval by the Department, the manufacturer's curve may be used to establish heat input rates over a range of temperature for the purpose of compliance determination."

Additionally, the following language will be added to footnote (*) in Table H.1.

> "Pollutant emission rates may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 90 days after the selection of the CT. Subject to approval by the Department, the manufacturer's curve may be used to establish pollutant emission rates over a range of temperature for the purpose of compliance determination."

If there are any questions or comments on the above, please call Syed Arif at (904) 488-1344.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

cc: Richard Donelan
Buck Oven
Greg Nelson, TEC
Larry Curtin, Holland & Knight

Florida Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

October 19, 1993

Mr. Thomas W. Davis, P.E.
Environmental Consulting & Technology, Inc.
3701 N.W. 98th Street
Gainesville, FL 32606

RE: Tampa Electric Company
Polk Power Station
Conditions of Certification

Dear Mr. Davis:

This letter is in response to your letter of October 14, 1993, requesting additions to the Conditions of Certification and is to inform you of the changes to the Conditions of Certification that we plan to make. This does not constitute authority to operate in accordance with the changes until the Conditions of Certification have been changed. Items No. 1, 3, 4, and 5 will be revised as outlined in your letter.

Item No. 2 of your letter relating to oil fuel bound nitrogen (FBN) adjustments cannot be accepted as presented. The range of FBN requested is much greater than other facilities. TECO has not presented data that shows ranges of the distillate fuel oil FBN content by weight within their system. When the fuel oil is required to have a maximum sulfur content of 0.05 percent by weight, as proposed for this project, the additional sulfur is removed by hydrotreating. FBN values are also reduced using this process.

Item No. 2 for FBN adjustments shall read as follows (based on FBN information for other facilities):

(2) The emission limit for NO_x is adjusted as follows for higher fuel bound nitrogen contents up to a maximum of 0.030 percent by weight:

FUEL BOUND NITROGEN (% by weight)	NO_x EMISSION LEVELS (ppmvd @ 15% O_2)
0.015 or less	42
0.020	44
0.025	46
0.030	48

using the formula STD = 0.0042 + F where:

STD = allowable NO_x emissions (% by volume at 15% O_2 and on a dry basis).

F = NO_x emission allowance for FBN defined by the following table:

FUEL BOUND NITROGEN (% by weight)	F (NO_x % by volume)
$0 < N < 0.015$	0
$0.015 < N \leq 0.03$	0.04 (N-0.015)

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

NO_x emissions are preliminary for the fuel oil specified in Specific Condition XIII. C of Conditions of Certification. The permittee shall submit fuel bound nitrogen content data for the low sulfur fuel oil prior to commercial operation to the Bureau of Air Regulation in Tallahassee, and on each occasion that fuel oil is transferred to the storage tanks from any other source to the Southwest District office in Tampa. The % FBN (z) following each delivery of fuel shall be determined by the following equation:

$$x(y) + m(n) = (x+m)(z)$$

where x = amount fuel in storage tank
y = % FBN in storage tank
m = amount fuel added
n = % FBN of fuel added
z = % FBN of composite

If there are any questions or comments on the above, please call Syed Arif at (904) 488-1344.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/SA/bjb

cc: Richard Donelan
Buck Oven
Greg Nelson, TEC
Larry Curtin, Holland & Knight

ECT
Environmental Consulting & Technology, Inc.

RECEIVED
OCT 15 1993
Division of Air Resources Management

October 14, 1993
ECT No. 90263-0502-1300

SENT BY FAX ON 10/14/93

Mr. Syed Arif
Florida Department of
Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Tampa Electric Company
Polk Power Station
Conditions of Certification

Dear Mr. Arif:

On behalf of Tampa Electric Company (TEC), the following comments with respect to the latest Conditions of Certification are provided for your consideration:

(1) To clarify the basis for the concentration values in Table H.1., add the following sentence to footnote (a):

"Pollutant concentrations in ppmvd are corrected to 15% oxygen."

(2) Add additional footnote to Table H.1. to address fuel bound nitrogen as follows:

Place ** after oil ppmvd for NO_x:

POLLUTANT	FUEL	BASIS[a]
NO_x	Oil	42 ppmvd**

Add footnote (**):

(**) Emission limitations are based on a fuel bound nitrogen (FBN) content of 0.015 weight percent or less. For FBN contents greater than 0.015 weight percent, the NO_x emission limit is adjusted as follows:

P.O. Box 8188
Gainesville, FL
32605-8188

3701 Northwest
98TH Street
Gainesville, FL
32606

(904)
332-0444

FAX (904)
332-6722

Fuel Bound Nitrogen (FBN) (% by weight)	NO_x Emission Limitation (ppmvd at 15% O_2)
FBN ≤ 0.015	42
0.015 < FBN ≤ 0.1	42 + (0.04 * FBN * 10,000)
0.1 < FBN ≤ 0.25	42 + ((0.004 + (0.0067 * (FBN-0.1))) * 10,000)
FBN > 0.25	42 + (0.005 * 10,000)

The FBN adjustments shown above are taken from New Source Performance Standard (NSPS) Subpart GG: 40 CFR §60.332(a)(3). An adjustment for FBN was included in early drafts of the FDEP Conditions of Certification.

(3) Condition H.5. on Page 17 should include the phrase "<u>corrected to 15% oxygen</u>" at the end of the condition.

(4) Revise Condition H.6. as follows: "The Department shall be provided with a test protocol including a time schedule 15 days prior to the <u>initial</u> test." There is no need to submit a protocol prior to each test.

(5) Revise Condition J., Performance Testing, to list the requirements separately for the combustion turbine and auxiliary boiler as follows:

Insert after first paragraph:

"<u>(a) Combustion Turbine</u>

List methods 1 - 10 as shown on Pages 18 and 19.

<u>(b) Auxiliary Boiler</u>

<u>1. Reference Method 9 for VE (I, A).</u>
<u>2. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I, A.).</u>
<u>3. Reference Methods 7, 7A, 7C, 7D, or 7E for NO_x (I, A).</u>

Other DEP approved methods may be used for compliance testing after prior departmental approval."

The test methods shown for the auxiliary boiler address only those pollutants for which emission limitations have been established per Condition I. A number of NO_x test methods are listed to provide flexibility in method selection.

Please call me at (904) 332-0444 or Greg Nelson of TEC at (813) 228-4847 if there are any questions.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Senior Engineer

TWD/tw

cc: Buck Oven, FDEP
Greg Nelson, TEC
Larry Curtin, Holland & Knight

ECT

Environmental Consulting & Technology, Inc.

October 7, 1993
ECT No. 90263-0502-1300

SENT BY FAX ON 10/7/93

RECEIVED
OCT 8 1993
Division of Air
Resources Management

Mr. Syed Arif
Florida Department of
Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

**Re: Tampa Electric Company
Polk Power Station**

Dear Mr. Arif:

Pursuant to the agreements reached at yesterday's meeting, a revised Site Certification Condition H.1. allowable emission table is attached together with the basis for the annual emission rates. The revised table shows the decrease in allowable SO_2 emissions from 0.247 to 0.170 lb/MMBtu for the post demonstration period. The maximum hourly SO_2 emission rate of 357 lb/hr from the 7F combustion turbine (CT) corresponds to the 0.170 lb/MMBtu limitation. As was agreed at the meeting, Tampa Electric Company (TEC) has the option of using lower sulfur coal, increasing the sulfur removal efficiency, any combination of these two control techniques, or any other means to meet the overall IGCC SO_2 limitation of 0.170 lb/MMBtu.

For completeness, the Site Certification Condition H.2. allowable emission table, together with the basis for the annual emission rates, are also attached. There are no changes to these tables from those previously provided to you.

As we discussed yesterday, the Polk Power Station SCA specifies a maximum annual capacity factor of ten percent for usage of back-up fuel oil in the 7F CT. Capacity factor is the ratio of the actual heat input to the 7F CT during a calendar year to the potential heat input had the 7F CT been operated 8,760 hours per year at its maximum heat input capacity. Accordingly, capacity factor is a function of <u>both</u> actual operating hours and load. The following table provides examples of the operating scenarios that could occur for a maximum ten percent fuel oil usage capacity factor:

P.O. Box 8188
Gainesville, FL
32605-8188

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98TH Street
Gainesville, FL
32606

(904)
332-0444

FAX (904)
332-6722

Capacity Factor (%)	Operating Hours (hrs/yr)	Operating Load (%)
10	1,752	50
10	1,168	75
10	876	100

The values shown above are for a maximum fuel oil capacity factor of ten percent; the actual fuel oil capacity factor in any given year may range from zero (7F CT fired exclusively with syngas) up to ten percent. By specifying a maximum capacity factor of ten percent for fuel oil usage, TEC is requesting permission to utilize back-up fuel oil in the 7F CT for the range of operating scenarios illustrated above. Because individual pollutant emission rates vary with load (heat input) and fuel type, the allowable annual emission rates specified in the PPS Conditions of Certification must cover the range of fuel oil usage, for each pollutant, corresponding to a minimum capacity factor of zero up to a maximum capacity factor of ten percent.

The concept of capacity factor can be addressed as a specific condition by simply specifying a maximum annual heat input rate during fuel oil-firing for the 7F CT; i.e., ten percent of the design maximum annual heat input. Suggested language to clarify the concept of capacity factor is as follows:

> "Use of back-up fuel oil in the IGCC combustion turbine shall be limited to a maximum annual capacity factor of ten percent. Maximum annual heat input to the IGCC combustion turbine shall not exceed 1.671 x 10^{12} Btu/yr when firing No. 2 fuel oil."

Please call me at (904) 332-0444 or Greg Nelson of TEC at (813) 228-4847 if there are any questions.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Senior Engineer

TWD/tw
Attachments

cc: Greg Nelson, TEC

ECT
Environmental Consulting & Technology, Inc.

TEC Polk Power Station

Site Certification Condition H.1.
Allowable Emission Table

Pollutant	Fuel	Basis[a]		Emission Limitations – 7FCT Post Demonstration Period	
		Value	Units	(lb/hr)[b]	(tpy)[c]
NO_x	Oil	42	ppmvd	311	N/A
	Syngas	25	ppmvd	222.5	1,015.3
VOC[d]	Oil	0.028	lb/MMBtu	32	N/A
	Syngas	0.0017	lb/MMBtu	3	38.5
CO	Oil	40	ppmvd	99	N/A
	Syngas	25	ppmvd	98	430.1
PM/PM_{10}[e]	Oil	0.009	lb/MMBtu	17	N/A
	Syngas	0.013	lb/MMBtu	17	74.5
Pb	Oil	5.30E−05	lb/MMBtu	0.101	N/A
	Syngas	2.41E−06	lb/MMBtu	0.0035	0.0657
SO_2	Oil	0.048	lb/MMBtu	92.2	N/A
	Syngas	0.170	lb/MMBtu	357	1,563.7
Visible Emissions	Oil	20 percent opacity			
	Syngas	10 percent opacity			

(a) Syngas lb/MMBtu values based on heat input (HHV) to coal gasifier and includes emissions from H_2SO_4 plant thermal oxidizer.

(b) Emission limitations in lb/hr are 30−day rolling averages.

(c) Annual emission limits (tpy) based on 10 percent maximum annual capacity factor firing fuel oil.

(d) Exclusive of background concentrations.

(e) Excluding sulfuric acid mist.

TEC Polk Power Station
Site Certification Condition H.1.
Post Demonstration Period
Basis For Annual Emission Rates

Pollutant	Fuel	Operating Period (hrs/yr)	Operating Load
NO_x	Oil	876	100
	Syngas	7,884	100
VOC	Oil	1,752	50
	Syngas	7,008	100
CO	Oil	1,752	50
	Syngas	7,008	100
PM/PM_{10}	Oil	876	100
	Syngas	7,884	100
Pb	Oil	1,752	50
	Syngas	7,008	100
SO_2	Oil	0	100
	Syngas	8,760	100

TEC Polk Power Station

Site Certification Condition H.2.
Allowable Emission Table

Pollutant	Fuel	Emission Limitations – 7FCT Demonstration Period	
		(lb/hr)[a]	(tpy)[b]
NO_x	Oil	311	N/A
	Syngas	664.2	2,908.3
VOC[c]	Oil	32	N/A
	Syngas	3	38.5
CO	Oil	99	N/A
	Syngas	99	430.1
PM/PM_{10}[d]	Oil	17	N/A
	Syngas	17	74.5
Pb	Oil	0.101	N/A
	Syngas	0.023	0.13
SO_2	Oil	92.2	N/A
	Syngas	518	2,268.8
Visible Emissions	Oil	20 percent opacity	
	Syngas	10 percent opacity	

(a) Emission limitations in lb/hr are 30–day rolling averages.

(b) Annual emission limits (tpy) based 10 percent maximum annual capacity factoı firing fuel oil.

(c) Exclusive of background concentrations.

(d) Excluding sulfuric acid mist.

TEC Polk Power Station
Site Certification Condition H.2.
Demonstration Period
Basis For Annual Emission Rates

Pollutant	Fuel	Operating Period (hrs/yr)	Operating Load
NO_x	Oil	0	0
	Syngas	8,760	100
VOC	Oil	1,752	50
	Syngas	7,008	100
CO	Oil	0	0
	Syngas	8,760	100
PM/PM_{10}	Oil	876	100
	Syngas	7,884	100
Pb	Oil	1,752	50
	Syngas	7,008	100
SO_2	Oil	0	0
	Syngas	8,760	100

Florida Department of
Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

October 7, 1993

Mr. Greg Nelson
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

RE: Polk Power Station
Conditions of Certification

Dear Mr. Nelson:

Pursuant to our agreement of October 6 the emission limits will be set as follows:

<u>NO_X Emission Limit</u>:

1) During the two year DOE hot gas clean up demonstration period, the stack emissions for NO_X shall not exceed 81 ppmvd at 15% oxygen or 664 lb/hr (2,908 TPY).

2) The permittee will install a combustor which is designed and manufactured to reach a goal of 10 ppmvd NO_X emission limit. This combustor will be utilized for the demonstration and post demonstration periods. After the demonstration period, the permittee shall operate the combustion turbine to achieve the lowest possible NO_X emission limit but shall not exceed 25 ppmvd.

3) The combustion turbine will be operated for 12-18 months after the demonstration period (estimated to be from Mid 1998 until December 31, 1999) in a cold gas clean up testing mode. During that period NO_X emission testing will be performed on the turbine at a regular interval of every 2 months. The Department shall be provided with a test protocol including a time schedule 15 days prior to the test. The permittee will provide the Department the emission test results 30 days after the test is performed. The Department shall be notified and the reasons provided if a scheduled test is delayed or canceled.

4) One month after the test period ends (estimated to be by February 2000), the permittee will submit to the Department a NO_X recommended BACT determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturers research. The Department will make a determination on the BACT for only NO_X and adjust the NO_X emission limits accordingly.

<u>SO_2 Emission Limit</u>:

1) During the two year DOE hot gas clean up demonstration period, the SO_2 emissions shall not exceed 0.247 lbs/MMBtu.

2) Following the demonstration period (estimated to be mid 1998), the SO_2 emissions shall be limited to 0.17 lbs/MMBtu.

The basis for the emission calculations issue we raised (capacity factors) is still under review, and will be resolved in consultation with Mr. Tom Davis of ECT. If there are any questions or comments on the above, please call Syed Arif at (904) 488-1344.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/SA/bjb

cc: Richard Donelan
Buck Oven

XIII. AIR

A. Operation and Construction

The construction and operation of Polk Power Station (Project) shall be in accordance with all applicable provisions of Chapter 17, F.A.C. The following emission limitations reflect final BACT determinations for Phase I (integrated gasification, combined cycle (IGCC) combustion turbine and auxiliary equipment) of the project fired with syngas or fuel oil. BACT determinations for the remaining phases will be made upon review of supplemental applications. In addition to the foregoing, the Project shall comply with the following conditions of certification as indicated.

B. Heat Input

The maximum heat input to the IGCC combustion turbine shall neither exceed 1,762 MMBtu/hr while firing syngas, nor 1,907 MMBtu/hr while firing No. 2 fuel oil.

C. Hours of Operation

The IGCC unit in Phase I may operate continuously, i.e., 8,760 hrs/year.

D. Fuel

Only syngas and low sulfur fuel oil shall be fired in the IGCC combustion turbine. Only low sulfur fuel oil shall be fired in the auxiliary boiler. The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05%, by weight.

E. Auxiliary Boiler

The maximum heat input to the auxiliary boiler shall not exceed 49.5 MMBtu/hr when firing No. 2 fuel oil with 0.05% maximum sulfur content (by weight). All fuel consumption must be continuously measured and recorded for the auxiliary boiler.

F. Fuel Consumption

The maximum coal input to the coal gasification plant shall not exceed 2,325 tons per day, on a dry basis.

G. Fugitive Dust

Fugitive dust emissions during the construction period shall be minimized by covering or watering dust generation areas. Particulate emissions from the coal handling shall be controlled by enclosing all conveyors and conveyor transfer points (except those directly associated with the coal stacker/reclaimer for which an enclosure is operationally infeasible). Fugitive emissions shall be tested as specified in Specific Condition No. ~~K.~~ J. Inactive coal storage piles shall be shaped, compacted, <u>and</u> oriented to minimize wind erosion.~~, and covered.~~ Water sprays or chemical wetting agents and stabilizers shall be applied to uncovered storage piles, roads, handling equipment, etc. during dry periods and, as necessary, to all facilities to maintain an opacity of less than or equal to 5 percent. When adding, moving or removing coal from the coal pile, an opacity of 20 percent is allowed.

H. Emission Limits

1. The maximum allowable emissions from the IGCC combustion turbine ~~unit~~, when firing syngas and low sulfur fuel oil, in accordance with the BACT determination, shall not exceed the following:

Pollutant	Fuel	Basis ***	Emissions Limitations - 7F CT: ~~IGCC~~ Initial year* lb/hr**	Initial year* TPY[a]	Post Demonstration Period lb/hr**	~~100% CCCU~~	TPY[b]
NOx	Oil	42 ppmvd	~~188~~ 311	164.7	~~164.7~~ 311		N/A
	Syngas	~~12.5~~ 25 ppmvd	N/A	N/A	222.5	~~111.25~~	1,044
VOC[c]	Oil	0.028 lb/MMBtu ~~32~~	~~28~~ 32	28	32		N/A
	Syngas	0.0017 lb/MMBtu	N/A	N/A	3	~~3~~	39.8
CO	Oil	~~30~~ 40 ppmvd	99	86.7	~~86.7~~ 99		N/A
	Syngas	25 ppmvd	N/A	N/A	98	~~98~~	429
PM/PM10[d]	Oil	~~0.014~~ 0.009 lb/MMBtu	~~23~~ 17	15	~~20.1~~ 17		N/A
	Syngas	0.018 lb/MMBtu	N/A	N/A	17	~~35~~	74
Pb	Oil	~~3.09~~ 5.303 E-5 lb/MMBtu	~~0.061~~ 0.101	0.053	0.101		N/A
	Syngas	~~1.98~~ 2.41 E-6 lb/MMBtu	N/A	N/A	0.0035	~~0.0035~~	0.067
SO_2	Oil	0.04~~7~~8 lb/MMBtu	~~58~~ 92.2	49.1	~~49.1~~ 92.2		N/A
	Syngas	~~0.17~~ 0.247 lb/MMBtu	N/A	N/A	518	~~373~~	2,269

Visible Emissions Gas 10 percent opacity
Oil 20 percent opacity

(*) Initial year operations based on a simple cycle combustion turbine with a 10 percent maximum annual capacity factor firing No. 2 fuel oil.

(**) Emission limitations in lbs/hr are 30-day rolling averages. ~~blocked 24-hour averages (midnight to midnight).~~

(***) Syngas lb/MMBtu values based on heat input (HHV) to coal gasifier and includes emissions from H_2SO_4 plant thermal oxidizer.

(a) Annual emission limits (TPY) based on 10 percent maximum annual capacity factor firing fuel oil.

(b) Annual emission limits (TPY) based on baseload operations firing syngas, with emission rates equivalent to 100-percent

CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(c) Exclusive of background concentrations.
(d) Excluding sulfuric acid mist.

2. The maximum allowable emissions from the IGCC Combustion turbi ~~unit~~, when firing syngas and No. 2 fuel oil during the two year ~~hot gas clean up (HGCU)~~ demonstration period, shall not exceed the following:

Pollutant	Emissions Limitations IFCT ~~IGCC~~ Syngas lb/hr*	Oil lb/hr*	TPYa
NO_X	664.2 ~~111.25~~	311	2,908 ~~522~~
VOC	~~8~~3	32	39.8
CO	99	99	434
PM/PM_{10} b	~~72~~ 17	17	~~315~~ 74
Pb	~~0.0035~~ 0.023	0.101	~~0.067~~ 0.14
SO_2	518	92.2	2,269
Visible Emissions	Gas 10 percent opacity Oil 20 percent opacity		

(*) Emission limitations in lbs/hr are ~~blocked~~ 30-day ~~24-hour averages (midnight to midnight).~~ rolling averages.

(a) Annual emission limits (TPY) based on baseload operations firing syngas, with a maximum of 8760 hrs/yr utilization of HGCU and up to 10-percent annual capacity factor firing No. 2 fuel oil.

(b) Excluding sulfuric acid mist.

3. The following turbine emissions, determined by BACT, are tabulated for PSD and inventory purposes:

Allowable Emissions

Pollutant	Fuel	IGCC Post Demonstration lb/hr	TPYa	IGCC 2-year Demonstration lb/hr	TPYb
Sulfuric Acidc	Syngas	55	241	55	241
Inorganic Arsenic	Syngas	0.0006	0.019	0.08	0.35
Beryllium	Syngas	0.0001	0.0029	0.0001	0.0029

Mercury	Syngas	0.0034	0.017	0.025	0.11

(a) Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(b) Based on baseload operations firing syngas, with a maximum of 8760 hrs/yr of HGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(c) Sulfuric acid mist emissions assume a maximum of 0.05 percent sulfur in the fuel oil.

4. Excess emissions from ~~a~~ the turbine resulting from startup, shutdown, malfunction, or load change shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the Department along with the initial compliance test data. The document may be updated as needed with all updates submitted to the Department within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

I. **Auxiliary Boiler Operation**

Operation of the auxiliary boiler shall be limited to a maximum of 1,000 hours per year and only during periods of startup and shutdown of the IGCC unit, or when steam from the IGCC unit's heat recovery steam generator is unavailable. The following emission limitations shall apply:

1. NO_x emissions shall not exceed 0.16 lbs/MMBtu for oil firing.

2. Sulfur dioxide emissions shall be limited by firing low sulfur fuel oil with a maximum sulfur content of 0.05 percent by weight.

3. Visible emissions shall not exceed 20 percent opacity (except for one six-minute period per hour during which opacity shall not exceed 27 percent), while burning low sulfur fuel oil.

J. **Performance Testing**

Initial (I) compliance tests shall be performed on ~~each~~ the turbine using both fuels and on the auxiliary. The stack test for ~~each~~ the turbine shall be performed between 90-100 percent of the maximum heat rate input for the tested operating temperature. Annual (A) compliance tests shall be performed on ~~each~~ the turbine with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using EPA reference methods in accordance with 40 CFR 60, Appendix A, as adopted by reference in Rule 17-297, F.A.C. and the requirements of 40 CFR 75:

1. Reference Method 5B for PM (I, A, for oil only)
2. Reference Method 8 for sulfuric acid mist (I, for oil only)
3. Reference Method 9 for VE (I, A)
4. Reference Method 10 for CO (I, A)
5. Reference Method 20 for NO_x (I, A)
6. Reference Method 18 for VOC (I, A)
7. Trace elements of Lead (Pb), Beryllium (Be) and Arsenic (As) shall be tested (I, for oil only) using Emission Measurement Technical Information Center (EMTIC) Interim Test Methods. As an alternative, Method 104 for Beryllium (Be) may be used; or Be and Pb may be determined from fuel analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.
8. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I,A)
9. ~~ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 for sulfur content of natural gas (I, and A if deemed necessary by der)~~ DEP
10. Reference Method 22 for fugitive emissions (I,A)

Other ~~der~~ DEP approved methods may be used for compliance testing after prior Departmental approval.

K. Sulfur Content of Fuel

The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent by weight. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing for sulfur content of the fuel oil in the storage tanks once per day when firing oil. Testing for fuel oil heating value, shall also be conducted on the same schedule.

L. Monitoring Requirements

A continuous emission monitoring system (CEMS) shall be installed, operated, and maintained in accordance with 40 CFR 60, Appendix F, for the combined cycle unit to monitor nitrogen oxides and a diluent gas (CO_2 or O_2). The applicant shall request that this condition of certification be amended to reflect the Federal Acid Rain Program requirements of 40 CFR 75 when those requirements become effective within the State.

1. Each CEMS shall meet performance specifications of 40 CFR 60, Appendix B.

2. CEMS data shall be recorded and reported in accordance with Chapter 17-297.500, F.A.C., 40 CFR 60 and 40 CFR 75. The record shall include periods of startup, shutdown, and malfunction.

3. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

4. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of all CEMS.

5. For purposes of the reports required under this permit, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Specific Condition No. H.4. herein, which exceeds the applicable emission limits in Condition No. H.

M. Notification, Reporting and Recordkeeping

To determine compliance with the syngas and fuel oil firing heat input limitation, the permittee shall maintain daily records of syngas and fuel oil consumption for ~~each~~ the turbine and the heating value for each fuel. All records shall be maintained for a minimum of two years after the date of each record and shall be made available to representatives of the Department upon request.

N. Applicable Requirements

The project shall comply with all the applicable requirements of Chapter 17, Florida Administrative Code (F.A.C.) and 40 CFR 60 Subparts A and GG. The requirements shall include:

1. 40 CFR 60.7(a)(1) - By postmarking or delivering notification of the start of construction no more than 30 days after such date;

2. 40 CFR 60.7(a)(2) - By postmarking or delivering notification of the anticipated date of the initial startup of each turbine and the auxiliary boiler not more than 60 days nor less than 30 days prior to such date;

3. 40 CFR 60.7(a)(3) - By postmarking or delivering notification of the actual startup of each turbine and the auxiliary boiler within 15 days of such date;

4. 40 CFR 60.7(a)(5) - By postmarking or delivering notification of the date for demonstrating the CEMSs performance, no less than 30 days prior to such date;

5. 40 CFR 60.7(a)(6) - By postmarking or delivering notification of the anticipated date for conducting the opacity observations no less than 30 days prior to such date;

6. 40 CFR 60.7(b) - By initiating a recordkeeping system to record the occurrence and duration of any startup, shutdown or malfunction of a turbine and the auxiliary boiler, of the air pollution control equipment, and when the CEMS is inoperable;

7. 40 CFR 60.7(c) - By postmarking or delivering a quarterly excess emissions and monitoring system performance report within 30 days of the end of each calendar quarter. This report shall contain the information specified in 40 CFR 60.7(c) and (d);

8. 40 CFR 60.8(a) - By conducting all performance tests within 60 days after achieving the maximum turbine and boiler firing rates, but not more than 180 days after the initial startup of each turbine and the auxiliary boiler;

9. 40 CFR 60.8(d) - By postmarking or delivering notification of the date of each performance test required by this permit at least 30 days prior to the test date; and

10. 17-297.345 - By providing stack sampling facilities for the combustion turbine. ~~and the auxiliary boiler~~.

All notifications and reports required by this specific condition shall be submitted to the Department's Air Program, within the Southwest District Office. Performance test results shall be submitted within 45 days of completion of such test.

O. **Submission of Reports**

The following information shall be submitted to the Department's Bureau of Air Regulation within 12 months of issuance of this permit:

1. Description of the final selection of the turbine and the auxiliary boiler to be installed at the facility. Descriptions shall include the specific make and model numbers, any changes in the proposed method of operation, fuels, emissions or equipment.

2. Description of the CEMS selected. Description shall include the type of sensors, the manufacturer and model number of the equipment.

3. If construction has not commenced within 18 months of issuance of this permit, then the permittee shall obtain from der a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2)). Units to be constructed or modified in later phases of the project will be reviewed and limitations revisited under the supplementary review process of the Power Plant Siting Act.

P. **Protocols**

The following protocols shall be submitted to the Department's Air Program, within the Southwest District Office, for approval:

1. CEMS Protocol - Within 60 days of selection of the CEMS, but prior to the initial startup, a CEMS protocol describing the system, its installation, operating and maintenance characteristics and requirements. The Department shall approve the protocol provided that the system and the protocol meet the requirements of 40 CFR 60.13, 60.334, Appendix B and Appendix F. This condition of certification shall be amended to reflect the Federal Acid Rain Program requirements of 40 CFR 75 when those requirements become effective within the State.

2. Performance Test Protocol - At least 90 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the Department's Air Program, within the Southwest District Office, a protocol outlining the procedures to be followed, the test methods and any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit. The Department shall approve the testing protocol provided that it meets the requirements of this permit.

Q. **Modifications**

The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change.

Memorandum

Florida Department of
Environmental Protection

TO: Richard Donelan

FROM: John Brown

DATE: September 30, 1993

SUBJ: TECO Certification Issues

The following are the issues still remaining to be resolved with TECO prior to the hearing.

Major Issues:

1) NO_x emission limit of 12.5 ppmvd on syngas vs. 25 ppmvd as suggested by TECO. DEP recommendation of 12.5 ppmvd is based on:

- Discussions with GE regarding their in-house testing of low NO_x burners on syngas and GE's confidence in achieving a 10 ppmvd without any controls. GE is suggesting that their in-house data could make it possible to achieve the limit of 10 ppmvd prior to the start of the TECO project.

- In the event that the 12.5 ppmvd cannot be accomplished with combustion control, data gathered by DEP from different vendors suggests that installing SCR for 50% NO_x removal can be achieved at a cost effectiveness of less than $4,000 per ton. The new data submitted by TECO on September 29, 1993 of $5,000 per ton is still under review.

2) SO_2 emission limit of 0.17 lb/MMBtu on syngas vs. 0.247 lb/MMBtu as suggested by TECO. DEP recommendation of 0.17 lb/MMBtu is based on:

- The last coal plant (Indiantown) was permitted at 0.17 lb/MMBtu. DEP has accepted the 0.247 lb/MMBtu emission limit during the 2-year hot gas clean up demonstration period, but the limit is established at 0.17 lb/MMBtu following the demonstration period. Should TECO be allowed to emit a higher level of SO_2 by utilizing a different technology rather than using coal to generate electricity?

- Data gathered from the coal shipments to the State suggests that the cost per ton of SO_2 removal is $830 vs. $7,000 as shown by TECO.

<u>Minor Issues</u>:

1) We do not agree with the basis of the emission table as presented by Holland & Knight in their correspondence to Buck Oven dated September 17, 1993. We are still awaiting response from ECT TECO's consultant) on this issue.

2) We are still awaiting data on coal gasification plant individual unit SO_2 removal efficiencies as promised by TECO in our last meeting of September 8, 1993.

In addition to the concerns expressed above, TECO's last minute amendment on their project should be a just cause for delaying the hearing. This is the second amendment that TECO has proposed since their filing of the Site Certification application. However, this amendment does not allow sufficient time to access the impact on the certification.

JB/SA/bjb

cc: Syed Arif
Clair Fancy
Preston Lewis
Doug Outlaw
Buck Oven

ECT
Environmental Consulting & Technology, Inc.

1. Dary
2. Syd

Environmental Consulting & Technology, Inc. - **ECT**

3701 Northwest 98th Street
Gainesville, Florida 32606
904/332-0444

TELECOPY COVERSHEET

TO: Preston Lewis

TELECOPY NUMBER: (904) 922-6979

FROM: Tom Davis

DATE: 09/29/93 CHARGE NO.: 90263-0502

WE ARE TRANSMITTING 14 PAGES, INCLUDING COVERSHEET. IF THE TRANSMISSION WAS NOT COMPLETE OR IF THE MESSAGE WAS NOT LEGIBLE, PLEASE CALL US IMMEDIATELY.

904/332-0444--SWITCHBOARD

904/332-6722--FACSIMILE MACHINE

904/332-6733--FACSIMILE MACHINE (Accounting)

COMMENTS: ______

The original of the transmitted document will be sent by:

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ECT

Environmental Consulting & Technology, Inc.

September 29, 1993
ECT No. 90263-0502-1300

SENT BY FAX ON 9/29/93

Mr. Doug Outlaw
Florida Department of
Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: **Tampa Electric Company**
Polk Power Station
SCR NO_x Control System Cost Analysis

Dear Mr. Outlaw:

During the meeting held in Tallahassee between FDEP personnel and representatives from Tampa Electric Company (TEC) and Environmental Consulting & Technology, Inc. (ECT) on September 8th, it was agreed that TEC/ECT would provide FDEP with additional information regarding the costs of a Selective Catalytic Reduction (SCR) NO_x control system for the Polk Power Station (PPS) IGCC facility based on vendor data. Please excuse the delay in providing this information. The vendors were requested to provide cost estimates supported by equipment lists and scope breakdowns to ensure that there would be no questions as to the validity and appropriateness of all costs presented in this analysis.

Revised Tables 4-32, 4-33, and 4-34 showing capital costs, annual operating costs, and cost-effectiveness, respectively, are attached for your review. Data contained in these tables are based on information received from General Electric Power Plant Systems Department (GE) and Henry Vogt Machine Company (Vogt). Vogt is presently under contract to supply the heat recovery steam generator (HRSG) for the PPS IGCC plant. Vogt has extensive experience with HRSG's including installations which incorporate SCR control systems. GE, the combined cycle supplier, would be required to integrate the entire HRSG/SCR system into the existing scope of supply and also meet all existing contract performance parameters. Copies of the correspondence received from these two firms are also attached.

Differences between the revised and original SCR cost analysis are summarized as follows:

- Total purchased equipment cost (PEC) of $3,335,063 is slightly higher

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(eight percent) than the original estimate. The revised PEC is based on actual vendor information expressed in 1995 dollars. It is noted that the PEC is for a complete NO_x control system installation which consists of much more than just the basic SCR reactor. Further details of the basis for the PEC are provided on Attachment I;

- Catalyst replacement cost is significantly (approximately 50%) lower than the original estimate apparently due to recent decreases in catalyst costs. A summary of the catalyst replacement costs provided to FDEP in permit applications for combined cycle combustion turbine projects is provided on Attachment II. This summary shows that the estimate for catalyst replacement cost received from the equipment vendors for the PPS project is the *lowest* of all recent estimates;

- Labor hours to replace the catalyst was reduced from five to three days, per vendor information;

- Contingency was reduced to 20 percent which is the lower bound of the range (20 to 25 percent) suggested by GE for a system with which no vendors have any prior experience; and

- The revised cost data results in a cost-effectiveness of approximately $5,000 per ton of NO_x removed for the application of a SCR control system to the PPS IGCC facility.

The revised SCR NO_x control system costs, reflective of current vendor information, represents a realistic estimate of the costs that would be incurred to install such a control system on the PPS IGCC project. As noted on Attachment II, the revised costs are well *below* estimates submitted to FDEP for other combustion turbine projects when viewed on a comparable ($/MW) basis.

Based on this analysis, the installation of a SCR NO_x control system is not warranted for the PPS project for the following reasons:

- IGCC is an alternative technology for using coal to produce power. FDEP and EPA have recently approved pulverized coal-fired plants in Florida which establish a NO_x BACT level of 0.17 lb NO_x/MMBtu. The level of NO_x emissions proposed for PPS, 0.099 lb NO_x/MMBtu, *is 42 percent lower* than the rates approved for the pulverized coal plants. IGCC technology also has a higher thermal efficiency than conventional coal-fired plants providing even lower emissions on a lb NO_x/MW basis. **The inherent benefit of the IGCC process in reducing NO_x emissions in comparison to conventional coal-fired plants is a BACT consideration.** Ignoring this consideration leads to the unreasonable conclusion that FDEP would approve a pulverized coal-fired plant at the PPS location equipped with an exhaust NO_x control system but not authorize an IGCC facility which emits approximately *50 percent less* NO_x for the same amount of power produced; and

- Cost-effectiveness of $5,000 per ton of NO_x removed, based on current vendor data, exceeds the level established by FDEP as being reasonable.

We would like to meet with you as soon as possible to resolve this issue. Because the PPS IGCC project pre-hearing conference is scheduled for this Monday, October 4th, we would appreciate the opportunity to meet with you this Friday, October 1st. Please call me at (904) 332-0444 or Greg Nelson of TEC at (813) 228-4847 if there are any questions.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Senior Engineer

TWD/tw
Attachments

cc: Preston Lewis, FDEP ✓
Clair Fancy, FDEP
Greg Nelson, TEC
Steve Jenkins, TEC
Jack Doolittle, ECT
Vilma Brueggemeyer, ECT
Larry Curtin, Holland & Knight

Revised 9/93

Table 4-32. Capital Costs for IGCC SCR NO_x Control System

Direct Costs	($)	OAQPS Factor
Purchased Equipment	3,335,063	A
Installation		
Foundations & Supports	266,805	0.08 * A
Handling & Erection	466,909	0.14 * A
Electrical	133,403	0.04 * A
Piping	66,701	0.02 * A
Insulation For Ductwork	33,351	0.01 * A
Painting	33,351	0.01 * A
Total Installation Cost	1,000,519	
Site Preparation	163,000	
Total Direct Cost	4,498,581	TDC
Indirect Costs	**($)**	**OAQPS Factor**
Engineering	333,506	0.10 * A
Construction & Field Expenses	166,753	0.05 * A
Contractor Fees	333,506	0.10 * A
Start-up	66,701	0.02 * A
Performance Test	33,351	0.01 * A
Contingency	667,013	0.20 * A
Total Indirect Cost	1,600,830	TIC
Interest During Construction	609,941	
Total Capital Investment	6,709,352	TCI

Sources: ECT, 1993.
GE, 1993.

Revised 9/93

Table 4−33. Annual Operating, Maintenance, and Catalyst Replacement Costs for IGCC SCR NO_x Control System

Direct Costs	($)	OAQPS Factor
Labor & Material Costs		
Operator	18,400	A
Supervisor	2,760	0.15 * A
Maintenance		
Labor	13,700	B
Materials	13,700	1.00 * B
Total Labor & Material Costs	48,560	C
Catalyst Costs		
Inventory (annualized)	145,447	
Replacement (materials + labor)	1,106,100	
Disposal	32,575	
Annualized Replace. & Disposal	458,362	
Total Annualized Catalyst Cost	603,809	
Utilities & Raw Materials		
Electricity	18,170	
Natural Gas	0	
Water	0	
Ammonia	52,305	
Total Utilities & Raw Materials	70,475	
Energy Penalties		
Turbine Backpressure	302,465	
Downtime For Catalyst Replacement (Annualized)	107,231	
Total Energy Penalties	409,696	
Total Direct Cost	1,132,540	TDC
Contingency	226,508	.20 * TDC
Indirect Costs	**($)**	**OAQPS Factor**
Overhead	29,135	0.60 * C
Administrative Charges	127,645	0.02 * TCI
Property Taxes	63,825	0.01 * TCI
Insurance	63,825	0.01 * TCI
Fixed Charges on Capital	739,680	
Total Indirect Cost	1,024,110	
Total Annual Cost	2,383,159	

Sources: ECT, 1993.
GE, 1993.

Table 4-34. Summary of NO_x BACT Analysis for the IGCC Unit

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact	Environmental Impacts: Adverse Environmental Impact
SCR	110.3	482.9	482.9	6,709,352	2,383,159	4,935	24,688	Yes	Yes
Baseline	220.5	965.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Note: Basis--IGCC unit, 100-percent CGCU, 100-percent load, 59°F ambient temperature, 90 percent annual capacity factor for syngas-firing, 10 percent annual capacity factor for distillate fuel oil-firing, and 50% SCR NO_x removal efficiency.

Source: ECT, 1993.

ATTACHMENT I
BASIS FOR SCR PURCHASED EQUIPMENT COST (PEC)

A SCR control system consists of a large number of components and subsystems which must be properly integrated with the power production facilities to be successful and maintain overall performance and efficiency. Specific components and services associated with each vendor are itemized as follows:

A. SCR Vendor Scope of Supply

1. Catalyst modules ready for installation
2. SCR catalyst housing with internal insulation and liner
3. Transition ducts
4. Internal catalyst modules support structure
5. Ammonia injection grid
6. Ammonia/Air dilution feed system
7. Ammonia skid instrumentation and controls

B. HRSG Vendor (Vogt) Scope of Supply

1. HRSG modifications to accommodate SCR system
2. Base plates and access doors
3. HRSG wallboxes for ammonia injection system
4. Monorail and hoist system for catalyst block removal
5. Internal support for ammonia injection lances
6. Interconnecting piping between ammonia distribution headers and lances, between distribution headers and ammonia skid, and between ammonia skid and HRSG
7. Overall engineering and equipment integration of SCR system with the HRSG

C. Combined Cycle Turbine (GE) Scope of Supply

1. Overall engineering/integration of HRSG/SCR system with power production equipment
2. Erection supervision and operator training
3. Primary responsibility for overall system performance, warranty, reliability, and availability

ATTACHMENT I
BASIS FOR SCR PURCHASED EQUIPMENT COST (PEC)
(continued)

D. **Engineer/Constructor Scope of Work**

1. Motor control centers (MCCs) for fans and pumps
2. Expansion of distributed control system (DCS) hardware and programming
3. Emission analyzer systems (NO_x and NH_3) including analyzers and conditioning equipment, if required
4. Ammonia storage tank and transfer pump

The GE SCR system cost estimate of $2,960,000 (in 1993 $) includes all of the scope of supply itemized above for the SCR, HRSG, and combined cycle turbine vendors (Items A, B, and C. above). Cost of the scope of supply for Item D (Engineer/Constructor) was estimated by GE at $65,000 (in 1993 $). The total PEC cost of $3,025,000 was adjusted to 1995 $ based on a 5 percent per year inflation rate as recommended by GE; i.e., multiplying by a factor of (1.05 * 1.05) or 1.1025. The resulting PEC, in 1995 $, is $3,335,063.

Attachment II – SCR Cost Comparison

Facility	Application Date	Rating (MW)	Fuels	Purchased Equipment SCR Capital ($)	Purchased Equipment SCR Capital ($/MW)	Total SCR Capital ($)	Total SCR Capital ($/MW)	Catalyst Replacement ($)	Catalyst Replacement ($/MW)	Catalyst Life (yrs)	Annualized SCR Cost ($/yr)	Annualized SCR Cost ($/MW)	Cost Effectiveness ($/ton)
PPS – 7F CT	Revised 9/93	200	Syngas/Oil	3,335,063	12,827	6,709,352	25,805	1,106,100	4,254	3	2,383,159	9,166	4,935
Polk Power Partners	4/3/92	84	Natural Gas/Oil	2,485,200	29,586	4,385,200	52,205	1,430,400	17,029	3	1,957,900	23,308	7,034
Auburndale	2/92	156	Natural Gas/Oil	2,275,000	14,583	4,717,075	30,238	1,170,000	7,500	3	2,283,326	14,637	6,900
Orlando Cogen	12/19/91	129	Natural Gas	2,572,100	19,939	4,694,300	36,390	1,489,200	11,544	3	1,900,300	14,731	14,308
Kissimmee Utility	11/14/91	80	Natural Gas/Oil	2,625,000	32,813	5,921,000	74,013	1,615,000	20,188	2	3,184,000	39,800	13,700
Pasco Cogen	5/1/91	108	Natural Gas/Oil	2,285,700	21,164	4,331,100	40,103	1,296,000	12,000	3	1,955,300	18,105	7,443
City of Lakeland	12/90	120	Natural Gas/Oil	2,190,000	18,250	3,330,000	27,750	1,090,000	9,083	7	2,190,000	18,250	7,960
FP&L Martin	11/89	200	Natural Gas/Oil	3,550,000	17,750	7,021,250	35,106	1,100,000	5,500	2	4,562,500	22,813	6,976
Maximum	N/A	200	N/A	3,550,000	32,813	7,021,250	74,013	1,615,000	20,188	3	4,562,500	39,800	14,308
Average	N/A	142	N/A	2,604,758	20,804	5,138,660	40,201	1,287,088	10,887	3	2,552,061	20,101	8,657
Minimum	N/A	80	N/A	2,190,000	12,827	3,330,000	25,805	1,090,000	4,254	2	1,900,300	9,166	4,935
PPS – 7F CT	Revised 9/93	200	N/A	3,335,063	12,827	6,709,352	25,805	1,106,100	4,254	3	2,383,159	9,166	4,935

GE Power Generation

Power Plant Systems Department
General Electric Company
1 River Road, Schenectady, NY 12345

CKV/IGPO/GE-VEN-006/93
September 23, 1993

(518) 385-1890
Building #23 - Room 362

Mr. Tom Davis
ECT Inc.
3701 Northwest 98th Street
Gainesville, Fl. 32606

Subject: TEC Polk Unit 1, SCR Costs

In accordance with your request of September 9 we have obtained the enclosed quote from Henry Vogt Machine Co. for addition of a 50% effective SCR to the HRSG scope of supply. Vogt's pricing and guaranteed life is included in the GE price of $2,960,000, which includes engineering integration and system guarantees.

In addition to the GE pricing, the following costs must be added to the SCR system costs for Polk Unit 1:

a) The cost of an aqueous ammonia storage facility and transfer pump must also be included in the evaluation. This is not supplied with the SCR equipment, but is normally provided in the balance of plant scope. We have included below an estimate for a 12 foot high by 12 foot diameter storage tank (30 day minimum capacity), field erected with containment provisions, and a forwarding pump.

b) Some additional DCS I/O capacity and software will be required. We estimate $10,000 for this.

Therefore, the total estimated price to consider for the addition of an SCR system is as follows:

GE SCR system	$2,960,000
Ammonia storage tank & pump	55,000
DCS Control	10,000
	==========
Total price, (93 $)	$3,025,000

Escalation of 5% per year to the date of order would apply to the above pricing, except for the tank and pump which are outside of the GE scope of supply.

Regarding the 25% contingency factor used for project and process uncertainty, we would consider it reasonable for this project. This is based on the assumption of applying a nominal 10% project contingency for a conventionally fueled plant, plus an additional 10 to 15% in consideration of the developmental nature of this syngas fueled project. This is especially true for the SCR catalyst system which has no prior operating experience with GT exhausts from coal gas fuel.

Very truly yours,

Carl K VanTine

Carl K. VanTine
Region Manager

CKV/bam
Enclosure

cc: S Jenkins -TEC
WE Behrens - #23-362
TC Lynch - #23-362
RF Racine - #23-362
WM Starr - #22-237
File

Vogt®

September 23, 1993

Mr. Jim Addison
General Electric Co.
Building 23, Room 361
1 River Road
Schenectady, NY 12345

Post-it™ brand fax transmittal memo 7671	# of pages ▸ 2
To TOM DAVIS	From PHIL SCHUPP
Co ECT	Co. VOGT
Dept.	Phone # 502/635-3372
Fax # 904/332-6722	Fax # 502/635-3015

Re: Vogt Job No. 17343
GE/TECO - Polk IGCC
SCR Scope of Supply

Dear Mr. Addison:

In response to the September 9, 1993, memorandum from Dick Cuscino to our Mark Steffen, Vogt hereby provides the following information for the supply of an SCR system for this project. The basis of the design is per the memo from Tom Davis - ECT to Ray Racine - GE dated September 9, 1993, which was attached to Mr. Cuscino's memo.

Pressure drop for this application is guaranteed at 4" H2O. Pressure drop can be decreased by increasing the catalyst assembly cross section, but this would require a physical configuration change.

Vogt's scope of supply would include the following:

1. SCR housing with insulation, liner, base plates, transition ducting and access doors.
2. Catalyst modules ready for installation.
3. Internal support structure for catalyst modules.
4. Hot gas recirculation type aqueous ammonia injection skid, lances and HRSG wallboxes.
5. Internal support structure for injection lances.
6. Monorail and hoist system for catalyst block removal.
7. An allowance for interconnecting piping between distribution headers and lances, distribution headers and skid, skid and HRSG (assuming skid to be within 50 feet of HRSG).
8. Instrumentation and controls for skid (basic package).

NOT included in Vogt's scope of supply would be:

1. MCC's for fan and pump motors.
2. 110 VAC power supply for instrumentation.
3. DCS system

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P.O. Box 1918 - Louisville, Kentucky 40201-1918 USA • Office & Plant: 1000 W. Ormsby Ave. - Louisville, Kentucky 40210-1810
Telephone: 502-634-1500 • Valve & Fitting/Corporate Fax: 502-637-7344 • Heat Transfer Fax: 502-634-0549 • Refrigeration Fax: 502-634-0479

Vogt

4. Emissions analyzers (NOx and NH3 sample systems).
5. Instrument air.
6. Purge air.
7. Ammonia storage tank.
8. Ammonia transfer pump.
9. Piping, pipe supports and valving for ammonia transfer system.
10. All piping insulation and lagging.
11. Vendor training and system checkout.
12. Erection supervision and start-up service.

In response to some of the other questions asked in the referenced memo.

A. Catalyst Replacement Frequency - 3 Years Minimum
B. Catalyst Replacement Cost - Approximately $1,000,000
C. Catalyst Changeout Labor - 72 Hours x 4 Men = 288 Manhours plus any required supervision, transfer costs from storage warehouse to site, etc.

Hopefully, these facts will suffice to answer the questions raised. If you are in need of further information, please call.

Very truly yours,

Philipp P. Schupp

Philipp P. Schupp
Project Manager
Heat Transfer Division

ljs

cc: D. Young
M. Steffen
R. Racine (GE - Fax: 518/385-0009)

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ENVIRONMENTAL ENGINEERING SERVICES

09/23/93

Atlas-Steuler Reference No. A930901B

Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Road
Tallahassee, FL 32399-2400

RECEIVED

SEP 27 1993

Division of Air Resources Management

Attention: Mr. Doug Outlaw
Telephone: (904) 488-1344
Telefax: (904) 922-6979

Reference: CER-NOx New Construction For GE-Frame 7 w/HRSG

Dear Mr. Outlaw:

Thank you for allowing ATLAS-STEULER the opportunity to offer you technical and budgetary information on your current SCR NO_X abatement engineering project. We have included information on our new recyclable catalyst formulation. We hope this information is timely. If you have any questions, please feel free to call at any time. We look forward to a meeting where we can discuss all the pertinant details of this project.

Sincerely,

ATLAS-STEULER DIVISION
ATLAS MINERALS & CHEMICALS, INC.

Jeffrey S. Sparks
Assistant National Sales Manager

attachments

Atlas Minerals & Chemicals, Inc.
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ATLAS-STEULER BUDGETARY PROPOSAL NUMBER A930901B:

EQUIPMENT: One (1) GE Combustion Turbine, Frame 7 with HRSG

PARAMETERS per Engine:

- Fuel	Coal Gas
- Exhaust Flow:	4,100,000 lb/hr
- Exhaust Temperature (^oF):	765 approximate
- NOx Emission (lb/hr):	233
- NOx Reduction Required (%):	50
- Expected Pressure Drop Across Catalyst Bed clean catalyst (inches WC):	2.62 with two (2) layers
- Guaranteed Ammonia Slip (ppmv):	10 maximum
- 100% NH_3 usage (lb/hr):	88.11*

*Assumes 50% reduction at maximum flow rate with NO_x assumed to be 90% NO and 10% NO_2. This is a critical number as it indicates minimal N_2O formation. Suspect catalysts will have lower ammonia consumption.

SCOPE OF SUPPLY:
CER-NOx III REACTOR HOUSING (horizontal design flow)
This housing will be designed by ATLAS-STEULER to accommodate the HRSG with flange connections. The housing and catalyst support, etc., will be supplied by the general contractor or others.
This catalyst section will be in the middle of the HRSG in a temperature window from 536^oF to 968^oF.

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Ammonia injection grid and piping arrangement designed by ATLAS-STEULER. The equipment will be supplied by general contractor or others. The injection array is installed in one section before the catalyst bed separated by one boiler section. The temperature in this region should not exceed 968°F due to oxidation of ammonia to NO_X.

One (1) Ammonia injection system skid mounted with all piping
flanged at connection to skid
Ammonia piping to be stainless steel
Metering panel to control flow with stainless steel valving
automated/manual course and fine adjustment of NH_3 flow
Pumps and piping sized to accommodate total required units for future expansion

One (1) Ammonia storage tank, 15,000 gallons U.S.
Single wall, carbon steel, chlorobutyl rubber lining inside and on all flange faces

One (1) CER-NOx III catalyst charge (zeolite modules)
Two (2) layers of CER-NOx III modules

Modules per layer:	array to be determined by HRSG cross-section
Total Modules:	approximately 9522
CER-NOx weight:	174,570 lbs

Module dimensions: 152mm x 152mm x 500mm (approx. 6" x 6" x 19.7")
Interior wall thickness: 1.4mm
Pitch: 4mm (28 CPSI) *compare to 200 CPSI of competitor* CER-NOx eliminates plugging concerns
Stainless steel mesh wrapping to absorb vibrations
Catalyst temperature limits - 536 to 968°F (with ammonia injection)
Stable to 1,292°F

INSTRUMENTATION AND CONTROLS
EMISSION ANALYZER

One (1) CEM to monitor total NO_X, CO, and O_2
Fully integrated PLC based control with 20% excess capacity
NO_2/NO converter (for total NOx measurement)
Photometric NO_X analyzer
CO Analyzer
O_2 Analyzer

CEM (cont.)

Time sharing logic as developed by Steuler to handle up to three systems with "NO_X emission learning"
State of the art sample transport and conditioning designed for extremely low maintenance

Total lump sum cost, F.O.B. Jobsite
$1,998,900.00

Guarantees 10 ppm ammonia slip

SCR Catalyst: Three (3) years or 20,000 operating hours (whichever occurs first) @ 50% reduction. In event catalyst does not meet the specification ATLAS-STEULER will remove/replace/add as required. There is no pro-rated guarantee as this is safe and based on experience.

Equipment: One (1) year for parts and components (not including moving components). ATLAS will remove/replace/repair defective equipment.

<u>NOTES AND EXCEPTIONS</u>:

1. Any applicable sales taxes, permits, permit fees etc. are not part of this quote and are the responsibility of the buyer.

2. Concrete, foundation, and steel work are not part of this quote and are to be provided by the owner or others.

3. Electrical connections, pipe welding, and pipe work are not part of this quote and are to be provided by the owner and/or others.

4. EPA certification testing is not part of this quote, however Atlas-Steuler will be available on the day(s) of scheduled tests.

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ATLAS-STEULER DIVISION TERMS & CONDITIONS

1. **ACCEPTANCE OF THIS PROPOSAL:** This proposal is subject to Buyer's acceptance within 30 days of the date of the proposal, and to the subsequent approval by Atlas-Steuler Division at Atlas Minerals & Chemicals, Inc. executive office at Mertztown, PA.

2. **TERMS:** Unless otherwise stated herein, the standard payment terms are 1/3 upon receipt of purchase order, 1/3 at delivery, balance will be progressive monthly billing for work completed, payable in 30 days from date of invoice. Prices are quoted F.O.B. Point of Origin. Should the purchaser delay payment beyond limits defined in Atlas-Steuler's proposal and customer's purchase order, then interest will be charged at the rate of 2% per month on any unpaid portion of the selling price. Payment is to be made to **Atlas Minerals & Chemicals, Inc.; P.O. Box 312; Lititz, PA 17543.**

3. **PRICING:** The prices quoted are based on cost of material, labor and freight existing at the date of this proposal. Should any costs increase, Buyer shall pay Seller such increased costs.

4. Additional costs from modifications of the order are the responsibility of the Buyer.

5. Work beyond the contractual agreement, which will be executed before or after the contractual work, will be invoiced at Atlas-Steuler's T&M rates in effect at the time of work.

6. This proposal does not include the costs of any Federal, State or Local permits that may be required. If required, all costs for attainment are for the account of the Buyer.

7. **TAXES:** Prices do not include either Federal, State or Local taxes. Any such taxes in effect at time of shipment are for the Buyer's account.

OBLIGATIONS OF THE BUYER

1. The Buyer is responsible to inform Atlas-Steuler about working conditions which must be taken into consideration for the execution of the order.

2. The Buyer agrees to treat information and/or documents, which are transmitted to him by Atlas-Steuler, as CONFIDENTIAL. Documents of Atlas-Steuler will not be made public or copied or used for other purposes than the original one without the permission of Atlas-Steuler. Breach of this agreement by the Buyer will qualify Atlas-Steuler to receive financial compensation.

3. Buyer shall, at his own expense, unload, safely store and convey all materials and equipment, as and when required, to the installation site. This includes hoisting to all levels required. Storage to be per Atlas-Steuler requirements.

4. Buyer shall, at his own expense, provide housing suitable to Atlas-Steuler for protection from the elements and maintain a minimum temperature of 65°F throughout said housing to avoid damage to the materials or equipment and to the installation in progress.

5. Buyer is to furnish at the point of use, when required, at his expense, scaffolding, and uninterrupted services including water, light, steam, compressed air, heat, ventilation and 110-220-440 volt, 60 cycle A. C. power.

6. Construction area is to be free of traffic and other factors leading to interruption of our workmen or damage to the installation. Other crafts will be excluded from the area in which our work is progressing as deemed necessary to insure a satisfactory installation.

7. When work is complete, Atlas-Steuler will gather up its construction debris and place it adjacent to the work area. Subsequent removal of this debris from the site is to be by the Buyer.

Form #A-S-112090 (5/13/93)

Cont'd on reverse side

NO_x Analyzer	
Make	HARTMANN & BRAUN
Model	RADAS 1G
Analysis Method	UV resonance absorption utilizing the gas filter correlation technique for NO
Selectable Ranges	0 - 100 ppm up to 0 - 1000 ppm
Minimum Detectable Concentration	5 ppm
Accuracy Full Scale	±1% of smallest span
Response Time Full Scale	down to 2 seconds depending on gas flow rate
Zero stability 168 hours	±2% of smallest span
Span stability 168 hours	±2% of smallest span
Zero-Span Stability 24 hours	better than ±1% of smallest span
O_2 Analyzer	
Make	HARTMANN & BRAUN
Model	MAGNOS 3
Analysis Method	Physical measurement of the paramagnetic behavior of O_2
Selectable Ranges	From 0 - 1 % O_2 to 0 - 100% O_2
Repeatability of Measured Value	<= 0.5% of span
Response Time Full Scale w/in 5 sec	<= 3.5 seconds
CO Analyzer	
Make	HARTMANN & BRAUN
Model	URAS 3 G
Analysis Method	Resonance absorption of heteroatomic gases
Optional Ranges	0 to 100 vol. % with suppression ranges of 6:1 and 4 adjustable measuring ranges
Repeatability of Measured Value	<= 0.5% of span
Response Time Full Scale w/in 5 sec	down to 1.5 seconds depending on gas flow rate

Sample Conditioning System

Make	ATLAS-STEULER
Model Number	N/A
Sample Dryer Type	HARTMANN & BRAUN type ECP

TECHNICAL QUALIFICATIONS

Experience

ATLAS MINERALS & CHEMICALS, INC. is a 101 year old corrosion control company in Mertztown, PA. ATLAS is the exclusive licensee for STEULER INDUSTRIEWERKE, GmbH, in Hohr-Grenzhausen, Germany, for turn-key supply and installation of engineered pollution control equipment.

The Steuler CER-NOx All Zeolite SCR technology has been in operation for over ten years around the world. The first commercial diesel application in the United States was installed by Steuler at Specialty Minerals, Inc., in Adams, Ma. This facility has coped very well in an especially dirty environment of poisoning, plugging, and masking elements for over four (4) years of continuous operation. Their plant manager, Mr. Fred Edgar is happy to discuss or allow tours of this facility. His phone number is (413) 743-0591.

ATLAS MINERALS & CHEMICALS, INC., offers continuous service for all installations. This includes maintenance service agreements, continuation training for new employees, etc.

Engineering Capability

All CER-NOx SCR operations to date were engineered by STEULER's Equipment division. This includes all submittals, mechanical, civil, and specialty labor at most sites. They have designed their systems to be easily maintained. Supply of equipment is developed to insure complete compatibility with existing equipment. The supply is also developed to allow standard trades to pipe the installation with ***no special knowledge requirements***.

Material selection through our corrosion engineering department meets our goal of long term service with little required maintenance and superior longevity.

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Design Capability

ATLAS/STEULER design teams will insure a complete understanding of piping, ducting, electrical, and other connections as required. The control equipment set-up and installation supervision is supplied to insure a successful on-time start-up.

Technology Factor

a. The SCR Unit

The CER-NOx III SCR system is centered around a unique catalyst made of an "all" zeolite material which offers it's unique 5-20 angstrom molecular sieve. The catalyst description follows:

Material - Natural and synthetic Zeolites with an aluminum oxide binder
Norton NC-300 zeolite is not used inour catalyst
Form - Extruded Monolith, approx. 28 cells per in^2 to prevent plugging
Interior wall thickness - 1.4 mm
Module size - 152mm x 152mm x 500mm
Module weight - 18.3 lbs
Active material - Over 85%
Disposal - returned to factory to be recycled into new catalyst!
Guaranteed Life - 3 years or 20,000 hours of operation
Expected life - first 1/2 of catalyst charge, 4 - 5 years
1/2 replaced approximately every 2- 4 years after that
Space velocity - 14,000 hr^{-1}

95% reduction is our standard process guarantee for all installations.

ATLAS-STEULER will insure proper mixing of ammonia through time-proven injection techniques with all required/appropriate safety precautions. Turbine applications at refineries in California have been proven $\pm$ 0.1% of perfect mixing by independant test authorities. Our thorough understanding of ammonia/urea as reducing reagents and their ability to stratify in the exhaust stream if not injected properly is unprecedented. Proper mixing allows for superb control of NO_x reduction as the byproduct.

Time proven testing, experience and computer modeling will be used to design the catalyst bed arrangement. This design and process is guaranteed.

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Process Description:

The CER-NOx III process is based on the Selective Catalytic Reduction Of NO_x to N_2 and water vapor. NO_x and injected ammonia vapor is moved into the micropore structure of the zeolite material through adsorption based on the concentration gradient.

Electrostatic forces in the micropores generate the activation energy necessary for the chemical reaction of NO_x, H_2O, and O_2 to nitrogen and water vapor. This reaction takes place safely at 536^oF to 968^oF. Thereafter, the reaction products are ejected out of the pores and dissipate in the exhaust stream.

The HRSG will house the ammonia injection grid in one section prior to the catalyst bed. This ammonia liquid (urea may also be used) is transported to the exhaust piping under pressure (approx. 4 bar). The ammonia is injected from atomizing nozzles and is immediately vaporized by the exhaust gas temperature. Ammonia is adjusted coarsely by monitoring engine loading and temperature (to indicate increase/decrease). Pre-programmed ammonia injection rates allow for quick load changes. Post reactor residual NO_x levels are measured for fine ammonia control and load following. These measurements actually update the ammonia injection curve and provide a learning effect to the software. This process has allowed us to control up to four engines with one controller. This operation also allows for ammonia as the limiting reagent and thus reduces ammonia slip.

There is only one NO_x measurement required to monitor up to four (4) SCR units. The individual flue gas streams are called up separately every 30 seconds and fed into the NO_x measurement and control system. The lapse time is bridged by the software learning effect of engine loading/programmed ammonia injection rates and the dampening effect of the Zeolite.

The CER-NOx III Zeolites have a sponge effect due to massive reaction surfaces developed by the micropore "sieve" structure. This area is approximately 3,000 ft^2 per gram of zeolite. This allows for slow residual NO_x changes and simple time sharing.

Engine loading and residual NO_x levels determine actual quantities of injected ammonia. Temperature controllers allow safety on/off valving. Below 536^oF the chemical SCR reaction would not take place and ammonia slip would be large. Ammonium bisulfate formation at these low temperatures also causes problems downstream. Above 968^oF the oxidation of ammonia to NO_x is so high it could cause a runaway condition....as more ammonia was injected, more NO_x is created. etc. Eventually, this exothermic reaction could progress to a level where all ammonia is burned to NO_x, thus the temperature controlled shut-down.

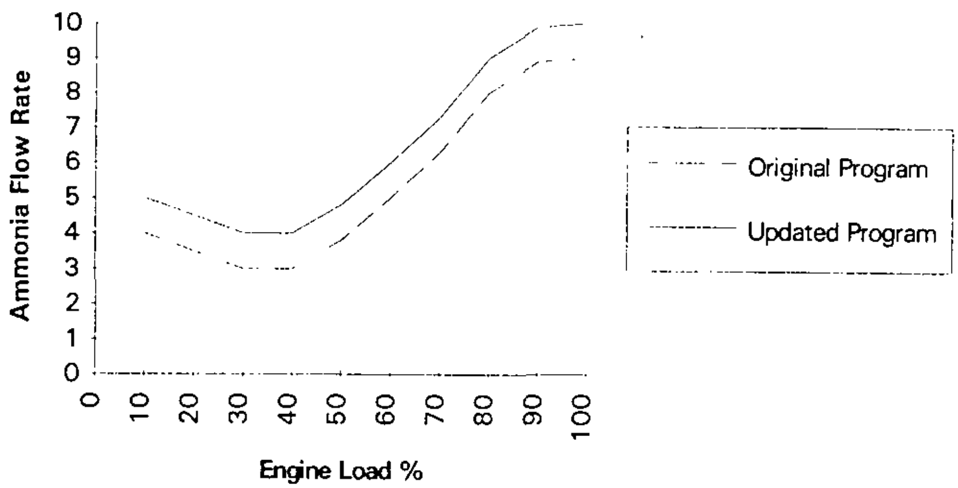
System Performance Factor

Control of this process is automated through a PLC based continuous emissions monitor (CEM). This system is dependent on a true state-of-the-art sample transport system that removes particulate, water, acids, and pollutants from the stream. The analyzers by Hartmann & Braun are proven, reliable, long life measuring devices with an unbeatable history of success. Gas flow to these monitors is sustained through engineered gas flow techniques with off-the-shelf-equipment from Swagelock and others.

The conditioned sample runs through a selector valve which determines whether calibration gases, actual samples, or zero samples will be measured. The flow is then precisely measured and sustained at equipment capable pressure before insertion into the monitors. These monitors relay analog output to the PLC and recorders for ammonia control and visual readout. All steps of this process are developed through PLC software that is correlated with a digital Theben clock. Calibration/Span gases are run once every 24 hours to check the monitor accuracy. An "EPA" port is supplied for a known gas insertion by others for CEM accuracy testing. The out-sample is vented to outside air or the reactor (as required).

The CEM/control cabinet is approximately 7' high, 6' wide, and 30" deep. Sample insertion is provided on the right half of the cabinet with the monitors, valving, flow control, scrubbers, and cooler. The left half of the cabinet contains the conditioned power supply with faraday shield, the PLC, input/output units, circuit breakers, timing mechanism, chart recorders, alarm readout/reset, and all process control switches/user interface. This cabinet will be in a climate controlled housing as specified.

LEARNING EFFECT



The ammonia injection learning effect is shown above. The original program line indicates flow rate generated due to engine load monitoring. The residual NO_X level indicates a change to the updated program. For example: If the residual NO_X level at 80% engine load indicated an ammonia flow of 8.5, the entire ammonia flow curve for all engine loadings would be memorized in the software as the updated program.

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CER-NOx III

All New Zeolite Catalyst Reformulation For Selective Catalytic Reduction of NO_X

CER-NOx III	**BENEFIT**
Extruded "All" Zeolite Monolith (Not a Washcoat!)	More Zeolite Reaction Sites With less than 15% Binder
Totally Recycled Into New Catalyst	No Waste/Disposal Concerns
28 Cells Per Square Inch vs. 200CPSI of Competitor	10 Years of Experience With No Plugging Concerns
Higher Operating Temperature	Can Handle Continuous Running With Ammonia @ 520°C (968°F)*

* Above this temperature, NH_3 oxidizes to NO_X at a very high rate

Higher Temperature Stability	CER-NOx Zeolites Are Stable Above 700°C (1,292°F) With No Deleterious Effects
Guaranteed Catalyst Performance	3 Years or 20,000 hours at 95% reduction. Proven by Experience.
Guaranteed System Performance	1 Year After Commissioning (*Not* Start-up!).
Longer Experience Based Catalyst Life (Only 1/4 Catalyst Replacement at Approx. 25,000 to 30,000 Hours in Diesel Operation... Based On Experience. *Not Test Data*).	Lower Operating Costs/Less Maintenance - Proven
Nearly Zero SO_2 to SO_3 Conversion	No Plugging Downstream Due To Ammonium Bisulfate Formation, Lower Acid Temperature Limiting Sulfuric Acid Formation/Corrosion.

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SCR CONTROL SYSTEM WITH CER-NOx III CATALYST BASE

CER-NOx III CONTROL	BENEFIT
Aqueous Ammonia, Anhydrous Ammonia Or Urea (No Odor or Explosion Problem) Can Be Used As A Reagent.	All Reagents And Associated Injection Techniques Proven By Experience.
Less Than 10 ppm Ammonia Slip.	*Guaranteed* to Meet EPA Limits (Based On Experience)
State-Of-The-Art Time Sharing Ability.	Developed By Steuler To Reduce Capital Costs And Still Follow Very Rapid Load Changes.
Superior Reactor Construction.	Long Service Life, Easy Access, Corrosion Resistant.
Premium Monitoring/Computer Supply	Long Term, Effective, Trouble Free Life - Lower Operating Cost - USA Supply
Total Engineering Services.	Develop Entire Turnkey System Using Manufacturers Engineering Capabilities.
USA Based Service.	ATLAS MINERALS & CHEMICALS, INC., a 101 Year Old Company, Staffed To Handle All Of Your Service Requirements

Contact:
ATLAS MINERALS & CHEMICALS, INC.
ATLAS-STEULER EQUIPMENT DIVISION, Jeff Sparks
FARMINGTON ROAD, POST OFFICE BOX 38
MERTZTOWN, PA 19539-0038
Telephone: (215) 682-7171
(800) 523-8269
Fax: (215) 682-9200

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
TAMPA ELECTRIC COMPANY
POLK POWER STATION
PA 92-32

CONDITIONS OF CERTIFICATION

I. GENERAL

A. Definitions

The meaning of the terms used herein shall be governed by the definitions contained in Chapters 403, 378, 373, 372, and 253, Florida Statutes, and any regulation adopted pursuant thereto and the statutes and regulations of any agency. In the event of any dispute over the meaning of a term used in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative, by the use of the commonly accepted meaning as determined by the department. As used herein:

1. "Application" shall mean the Site Certification Application (SCA) for the Polk Power Station Project, as supplemented.

2. "DEP" shall mean the Florida Department of Environmental Protection.

3. "DHR" shall mean the Florida Department of State, Division of Historical Resources.

4. "Emergency conditions" shall mean urgent circumstances involving potential adverse consequences to human life or property as a result of weather conditions or other calamity, and necessitating new or replacement gas pipeline, transmission lines, or access facilities.

5. "Feasible" or "practicable" shall mean reasonably achievable considering a balance of land use impacts, environmental impacts, engineering constraints, and costs.

6. "GFWFC" shall mean the Florida Game and Freshwater Fish Commission.

7. "Permittee" shall mean Tampa Electric Company (TECO).

8. "Power plant" shall mean the electric power generating equipment and appurtenances to be constructed on the Polk Power Station site in Polk County, as generally depicted in the Application.

9. "Project" shall mean the TECO Polk Power Station (PPS) and all associated facilities, including: the power plant, coal gasification plant, sulfuric acid plant and related facilities; and the cooling reservoir and related facilities.

10. "SWFWMD" shall mean the Southwest Florida Water Management District.

11. "ISO" shall mean International Organization for Standardization, ISO 3977-1978(E) standard conditions for gas turbines = 14.7 psia, 15^{o}C, relative humidity 60%.

B. Applicable Rules

The construction and operation of the PPS shall be in accordance with all applicable provisions of at least the following regulations of DER: Chapters 17-2, 17, 25 17-256, 17-296, 17-297, 17-321, 17-322, 17-302, 17-531, 17-532, 17-550, 17-555, 17-560, 17-650, 17-660, 17-701, 17-4, 17-25 and 17-610, Florida Administrative Code (F.A.C.) or their successors as they are renumbered.

II. CHANGE IN DISCHARGE

All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any regulated pollutant not identified in the application, or more frequent than, or at a level in excess of that authorized herein, shall constitute a violation of the certification. Any anticipated facility expansions beyond the certified initial nameplate capacity of 260 MW, production increases, or process modifications which may result in new, different, or increased discharges of pollutants, change in type of fuel as described in XIII.D., or expansion in steam generation capacity shall be reported by submission of a supplemental application pursuant to Chapter 403, Florida Statues.

III. GENERAL CONDITIONS

A. Facilities Operation

1. The Permittee shall at all times maintain in good working order and operate as efficiently as possible all treatment or control facilities or systems installed or used by the Permittee to achieve compliance with the terms and conditions of this certification. In the event of a malfunction of a electric generating unit's pollution control system, that unit's load shall be shifted to any or all of the remaining units having a properly functioning pollution control system, and the malfunctioning unit shall be promptly shut down.

2. In the event of a prolonged (thirty (30) days or more) equipment malfunction or shutdown of air pollution control equipment, operation may be allowed to resume and continue to take place under an appropriate Department order, provided that the Permittee demonstrates that such operation will be in compliance with all applicable ambient air quality standards and PSD increments, solid waste rules, domestic waste rules and industrial waste rules. During such malfunction or shutdown, the operation of the Polk Power Station (PPS) shall comply with all other requirements of this certification and all applicable state and federal emission standards not affected by the malfunction or shutdown which is the subject of the Department's order. Operational stoppages exceeding two hours for air pollution control systems or four hours for other systems or operational malfunctions as defined in the operational contingency plans as specified in Condition XVI are to be reported as specified in Condition III.B. Identified operational malfunctions which do not stop operation but do compromise the integrity of the operation shall be reported to the Southwest District Office as specified in Condition III.B.

3. TECO shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the TECO to achieve compliance with the conditions of this Certification, and are required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the approval and when required by Department rules.

B. Non-Compliance Notification

If, for any reason, the Permittee (defined as the Applicant or its successors and or assigns) does not comply with or will be unable to comply with any limitation specified in this certification, the Permittee shall notify the Southwest District Office of the Department of Environmental Protection by telephone within a working day that said noncompliance occurs and shall confirm this in writing at 3804 Coconut Palm Drive, Tampa, Florida 33619-8318 within seventy-two (72) hours of becoming aware of such conditions, and shall supply the following information:

1. A description of the discharge and cause of noncompliance; and,

2. The period of noncompliance, including exact dates and times; or if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the noncomplying event.

C. Safety

The overall design, layout, and operation of the facilities shall be such as to minimize hazards to humans and the environment. Security control measures shall be utilized to prevent exposure of the public to hazardous conditions. The Federal Occupational Safety and Health Standards will be complied with during construction and operation. The Safety Standards specified under Section 440.56, Florida Statutes, by the Industrial Safety Section of the Florida Department of Commerce will also be complied with.

D. Enforcement

1. The Secretary may take any and all lawful actions as he or she deems appropriate to enforce any condition of this certification.

2. Any participating agency (federal, state, local) may take any and all lawful actions to enforce any condition of this certification that is based on the rules of that agency. Prior to initiating such action the agency head shall notify the Secretary of that agency's proposed action.

E. Design and Performance Criteria

The power plant may be operated at up to 115% of the maximum electrical output at ISO conditions projected from design information without the need for modifying these conditions. Treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this certification are not to be bypassed without prior DER approval. Moreover, the Permittee shall take all reasonable steps to minimize any adverse impacts resulting from noncompliance with any limitation specified in this certification, including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying event.

F. Certification

1. The terms, conditions, requirements, limitations and restrictions set forth in these conditions of certification are binding and enforceable pursuant to Sections 403.141, 403.161, 403.514, 403.727, or 403.859 through 403.861, Florida Statutes. TECO is placed on notice that the Department will review this approval periodically and may initiate enforcement action for any violation of these conditions.

2. This approval is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from

the approved drawings, exhibits, specifications, or conditions of this approval may constitute grounds for revocation and enforcement action by the Department.

3. As provided in subsections 403.087(6) 403.511, and 403.722(5), F.S., the issuance of this approval does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, State, or local laws or regulations. This approval is not a waiver of or approval of any other Department approval that may be required for other aspects of the total project under federally delegated programs which are not addressed in this certification.

4. This certification does not relieve the TECO from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this approved source, or from penalties therefore; nor does it allow the TECO to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

5. In accepting this certification, TECO understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this approved source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the approved source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

6. TECO agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the TECO does not waive any other rights granted by Florida Statutes or Department rules.

7. This certification is transferable only upon Department approval in accordance with section 403.516, F.S., Rule 17-4.120 and 17-730.300, Florida Administrative Code, as applicable. TECO shall be liable for any non-compliance of the approved activity until the transfer is approved by the Department.

8. These conditions of certification or a copy thereof shall be kept at the work site of the approved activity.

9. TECO shall comply with the following:

a) Upon request, TECO shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) TECO shall hold at the facility or other location designated by this approval records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the approval, copies of all reports required by this approval, and records of all data used to complete the application for this approval. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. the date, exact place, and time of sampling or measurements;

2. the person responsible for performing the sampling or measurements;

3. the dates analyses were performed;

4. the person responsible for performing the analyses;

5. the analytical techniques or methods used;

6. the results of such analyses.

10. When requested by the Department, TECO shall within a reasonable time furnish any information required by law which is needed to determine compliance with the certification. If TECO becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

G. Laboratories and Quality Assurance

1. The permittee shall ensure that all laboratory analytical data submitted to the Department, as required by this permit, must be from a laboratory which has a currently valid and Department approved comprehensive Quality Assurance Plan (QAP) [or a QAP pending approval] for all parameters being reported, as required by Chapter 17-160, Florida Administrative Code.

2. When a contract laboratory is used to analyze samples required pursuant to this permit, the permittee is required to have the samples taken by qualified personnel following EPA and Department approved sampling procedures and chain-of-custody requirements. All chain-of-custody records

must be retained by the contract laboratory for at least five (5) years and made available to the Department immediately upon request.

3. When an in-house laboratory is used to analyze samples required pursuant to this permit, the permittee is required to have the samples taken by a qualified technician following EPA and Department approved sampling procedures and chain-of-custody requirements. All chain-of-custody records must be retained on-site for at least five (5) years and made available to the Department immediately upon request.

IV. ADVERSE IMPACT

The Permittee shall take all reasonable steps to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification, including such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying discharge.

V. RIGHT OF ENTRY

The Permittee shall allow during operational or business hours the Secretary of the Florida Department of Environmental Protection and/or authorized representatives, including representatives of the SWFWMD upon the presentation of credentials:

1. To enter upon the Permittee's premises where an effluent source is located or in which records are required to be kept under the terms and conditions of this certification;

2. To have access during normal business hours (Mon.-Fri., 9:00 a.m. to 5:00 p.m.) to any records required to be kept under the conditions of this certification for examination and copying;

3. To inspect and test any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants, or monitor any substances or parameters at any location reasonably necessary to assure compliance with this certification or Department rules;

4. To assess any damage to the environment or violation of ambient standards; and,

5. Reasonable time may depend on the nature of the concern being investigated.

VI. REVOCATION OR SUSPENSION

This certification may be suspended or revoked for violations of any of its conditions pursuant to Section 403.512, Florida Statutes.

VII. CIVIL AND CRIMINAL LIABILITY

This certification does not relieve the Permittee from civil or criminal penalties for noncompliance with any conditions of this certification, applicable rules or regulations of the Department or Chapter 403, Florida Statutes, or regulations thereunder.

Subject to Section 403.511, Florida Statutes, this certification shall not preclude the institution of any legal action or relieve the Permittee from any responsibilities or penalties established pursuant to any other applicable State Statues, or regulations.

VIII. PROPERTY RIGHTS

The issuance of this certification does not convey any property rights in either real or personal property, nor any exclusive privileges, nor does it authorize any injury to public or private property or any invasion of personal rights nor any infringement of Federal, State or local laws or regulations.

This certification conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

IX. SEVERABILITY

The provisions of this certification are severable, and if any provision of this certification or the application of any provision of this certification to any circumstances, is held invalid, the application of such provisions to other circumstances and the remainder of the certification shall not be affected thereby.

X. REVIEW OF SITE CERTIFICATION

The certification shall be final unless revised, revoked, or suspended pursuant to law. At least every five years from the date of issuance of certification the Department shall review these conditions of certification and propose any needed changes.

XI. MODIFICATION OF CONDITIONS

Pursuant to Subsection 403.516(1), F.S., the Board hereby delegates the authority to the Secretary to modify any condition of this certification dealing with sampling, monitoring, reporting, specification of control equipment, related time schedules, emission limitations, conservation easements, transfer or assignment of the Certification, approval of amendments to mine reclamation programs, issuance or modification of any related federally delegated permits, or any special studies conducted, as necessary to attain the objectives of Chapter 403, Florida Statutes.

All other modifications to these conditions shall be made in accordance with Section 403.516, Florida Statutes.

XII. CONSTRUCTION

A. Standards and Review of Plans

1. The facility shall be constructed pursuant to the design standards presented in the application and the standards or plans and drawings submitted and signed by an engineer registered in the state of Florida. The Applicant shall present specific facility plans, as developed, for review by the Southwest District Office at least 90 days prior to construction of those portions of the facility for which the plans are then being submitted, unless other time limits are specified in the following conditions herein. Specific Southwest District Office acceptance of plans will be required based upon a determination of consistency with approved design concepts, regulations and these Conditions prior to initiation of construction of the: industrial waste treatment facilities; domestic waste treatment facilities; potable water treatment and supply systems; ground water monitoring systems, off-site water and wastewater pipelines; transmission lines; stormwater run-off systems; and hazardous, toxic or pathological handling facilities or areas. Review and action by the Southwest District Office on said plans shall be accomplished in a timely fashion in accordance with Chapter 120, F.S. from the date of a complete submittal of such plans and any action may be subject to review pursuant to Chapter 120, Florida Statutes.

2. One year prior to the anticipated date of first operation, TECO shall provide the Department with an itemized list of any changes made to the facility design and operation plans since the time of the approval of these conditions. This pre-operational review of the final design and operation shall demonstrate continued compliance with Department rules and standards.

B. Control Measures

1. Stormwater Run-off

To control run-off during construction which may reach and thereby pollute Waters of the State, necessary measures shall be utilized to settle, filter, treat or absorb silt-containing or pollutant-laden storm water to ensure against spillage or discharge of excavated material that may cause turbidity in excess of 29 Nephelometric Turbidity Units above background in Waters of the State. Control measures may consist of sediment traps, barriers, berms, and vegetation plantings. Exposed or disturbed soil shall be protected and stabilized as soon as possible to minimize silt and sediment laden run-off. The pH of the run-off shall be kept within the range of 6.0 to 8.5. The Permittee shall comply with Florida Administrative Code Chapters 17-25, 40D-2, and 40D-4. The Permittee shall complete the forms required by 17-25.09(1) and 40D-4 and submit those forms and the required information to the SWFWMD for any modifications that might occur.

2. Open Burning

Open burning in connection with initial land clearing shall be in accordance with Chapter 17-256, F.A.C., Chapter 5I-2, F.A.C., Uniform Fire Code Section 33.101 Addendum, and any other applicable County regulation.

Any burning of construction generated material, after initial land clearing that is allowed to be burned in accordance with Chapter 17-256, F.A.C., shall be approved by the Southwest District Office in conjunction with the Division of Forestry and any other County regulations that may apply. Burning shall not occur unless approved by the appropriate agency or if the Department or the Division of Forestry has issued a ban on burning due to fire safety conditions or due to air pollution conditions.

3. Sanitary Wastes

Disposal of sanitary wastes from construction toilet facilities shall be in accordance with applicable regulations of the appropriate local health agency.

4. Solid Wastes

Solid wastes resulting from construction shall be disposed of in accordance with the applicable regulations of Chapter 17-701, F.A.C.

5. Noise

Construction noise shall not exceed either local noise ordinance specifications, or those noise standards imposed by zoning.

6. Dust and Odors

The Permittee shall employ proper odor and dust-control techniques to minimize odor and fugitive dust emissions. The applicant shall employ control techniques sufficient to prevent nuisance conditions on adjoining property.

7. Transmission Lines

The directly associated transmission lines from the PPS electric generators to the existing TECO transmission lines shall be cleared, maintained, and prepared in accordance with the application and the appropriate state and federal regulations concerning use of herbicides. TECO shall notify the Department of the type of herbicides to be used at least 60 days prior to use. Wetland mitigation shall be accomplished in accordance with Chapter 17-312, F.A.C. Wetland mitigation proposals shall be submitted to the Department at least 90 days prior to start of construction.

8. Protection of Vegetation

The Permittee shall develop the site so as to retain a buffer of trees or shall plant a buffer of trees sufficient to minimize the aesthetic and noise impacts of the facility. The buffer, as far as practicable, shall be of sufficient height and width suitable for the purpose of mitigating both construction and operational impacts of the facility.

9. Dewatering Operations

The dewatering operations during construction shall be carried out in such a manner that all water withdrawn will be retained on site. There shall be no discharge of water off site due to dewatering operations unless approved by the Department and SWFWMD.

10. Historical or Archaeological Finds

If historical or archaeological artifacts, such as Indian canoes, are discovered at any time within the project site, the permittee shall notify the DEP Southwest District office and the Bureau of Historic Preservation, Division of Archives, History and Records Management, R.A. Gray Building, Tallahassee, Florida 32399, telephone number (904) 487-2073.

C. Environmental Control Program

An environmental control program shall be established under the supervision of a Florida registered professional engineer to assure that all construction activities conform to applicable environmental regulations and the applicable Conditions of Certification. If a violation of standards, harmful effects or irreversible environmental damage not anticipated by the application or the evidence presented at the certification hearing are detected during construction, the Permittee shall notify the Southwest District Office as required by Condition II.

D. Reporting

1. Notice of commencement of construction shall be submitted to the Southwest District Office within 15 days of initiation. Starting three (3) months after construction commences, a quarterly construction status report shall be submitted to the Southwest District Office. The report shall be a short narrative describing the progress of construction.

2. Upon or immediately prior to completion of construction of the PPS or a phase thereof and upon or immediately prior to completion of all necessary preparation for the operation of the onsite potable water supply, domestic or industrial waste treatment facility, ground water monitoring system, brine pond or landfill, the Southwest District Office will be notified of certification of construction completion and a date on which a site or facility inspection can be performed in accordance with Condition V.

XIII. AIR

A. Operation and Construction

The construction and operation of Polk Power Station (Project) shall be in accordance with all applicable provisions of Chapter 17, F.A.C. The following emission limitations reflect final BACT determinations for Phase I (integrated combined cycle (IGCC) combustion turbines and auxiliary equipment) of the project fired with syngas or fuel oil. BACT determinations for the remaining phases will be made upon review of supplemental applications. In addition to the foregoing, the Project shall comply with the following conditions of certification as indicated.

B. Heat Input

The maximum heat input to the IGCC combustion turbine shall neither exceed 1,762 MMBtu/hr while firing syngas, nor 1,907 MMBtu/hr while firing No. 2 fuel oil.

C. Hours of Operation

The IGCC unit in Phase I may operate continuously, i.e., 8,760 hrs/year.

D. Fuel

Only syngas and low sulfur fuel oil shall be fired in the IGCC combustion turbine. Only low sulfur fuel oil shall be fired in the auxiliary boiler. The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05%, by weight.

E. Auxiliary Boiler

The maximum heat input to the auxiliary boiler shall not exceed 49.5 MMBtu/hr when firing No. 2 fuel oil with 0.05% maximum sulfur content (by weight). All fuel consumption must be continuously measured and recorded for the auxiliary boiler.

F. Fuel Consumption

The maximum coal input to the coal gasification plant shall not exceed 2,325 tons per day, on a dry basis.

G. Fugitive Dust

Fugitive dust emissions during the construction period shall be minimized by covering or watering dust generation areas. Particulate emissions from the coal handling shall be controlled by enclosing all conveyors and conveyor transfer points (except those directly associated with the coal stacker/reclaimer for which an enclosure is operationally infeasible). Fugitive emissions shall be tested as specified in Specific Condition No. ~~K.~~ J Inactive coal storage piles shall be shaped, compacted, oriented to minimize wind erosion, and covered. Water sprays or chemical wetting agents and stabilizers shall be applied to uncovered storage piles, roads, handling equipment, etc. during dry periods and, as necessary, to all facilities to maintain an opacity of less than or equal to 5 percent. When adding, moving or removing coal from the coal pile, an opacity of 20 percent is allowed.

H. Emission Limits

1. The maximum allowable emissions from the IGCC unit, when firing syngas and low sulfur fuel oil, in accordance with the BACT determination, shall not exceed the following:

			Emissions Limitations			
			IGCC			
Pollutant			Initial year*			100% CGCU
	Fuel	Basis	lb/hr**	TPY[a]	lb/hr**	TPY[b]
NOx	Oil	42 ppmvd	188		164.7	
	Syngas	12.5 ppmvd				111.25
VOC[c]	Oil	0.028 lb/MMBtu 32	28			
	Syngas	0.0017 lb/MMBtu				3
CO	Oil	30 ppmvd	99		86.7	
	Syngas	25 ppmvd				98
PM/PM_{10}	Oil	0.014 lb/MMBtu	23		20.1	
	Syngas	0.018 lb/MMBtu				35
Pb	Oil	3.09E-5 lb/MMBtu	0.061	0.053		
	Syngas	1.98E-6 lb/MMBtu				0.0035
SO_2	Oil	0.047 lb/MMBtu	56		49.1	
	Syngas	0.17 lb/MMBtu				373
Visible Emissions	Gas	10 percent opacity				
	Oil	20 percent opacity				

(*) Initial year operations based on a simple cycle combustion turbine with a 10 percent maximum annual capacity factor firing No. 2 fuel oil.

(**) Emission limitations in lbs/hr are blocked 24-hour averages (midnight to midnight).

(a) Annual emission limits (TPY) based on 10 percent maximum annual capacity factor firing fuel oil.

(b) Annual emission limits (TPY) based on baseload operations firing syngas, with emission rates equivalent to 100-percent

CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(c) Exclusive of background concentrations.

2. The maximum allowable emissions from the IGCC unit, when firing syngas and No. 2 fuel oil during the two year hot gas clean up (HGCU) demonstration period, shall not exceed the following:

Pollutant	Emissions Limitations IGCC lb/hr*	TPY[a]
NO_x	111.25	522
VOC	9	39.8
CO	99	434
PM/PM_{10}	72	315
Pb	0.0035	0.067
SO_2	518	2269
Visible Emissions	Gas 10 percent opacity Oil 20 percent opacity	

(*) Emission limitations in lbs/hr are blocked 24-hour averages (midnight to midnight).

(a) Annual emission limits (TPY) based on baseload operations firing syngas, with a maximum of 8760 hrs/yr utilization of HGCU and up to 10-percent annual capacity factor firing No. 2 fuel oil.

3. The following turbine emissions, determined by BACT, are tabulated for PSD and inventory purposes:

Allowable Emissions

Pollutant	Fuel	IGCC Post Demonstration lb/hr	TPY[a]	IGCC 2-year Demonstration lb/hr	TPY[b]
Sulfuric Acid[c]	Syngas	55	241	55	241
Inorganic Arsenic	Syngas	0.0006	0.019	0.08	0.35
Beryllium	Syngas	0.0001	0.0029	0.0001	0.0029

Mercury	Syngas	0.0034	0.017	0.025	0.11

(a) Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(b) Based on baseload operations firing syngas, with a maximum of 8760 hrs/yr of HGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(c) Sulfuric acid mist emissions assume a maximum of 0.05 percent sulfur in the fuel oil.

4. Excess emissions from a turbine resulting from startup, shutdown, malfunction, or load change shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the Department along with the initial compliance test data. The document may be updated as needed with all updates submitted to the Department within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

J. Auxiliary Boiler Operation

Operation of the auxiliary boiler shall be limited to a maximum of 1,000 hours per year and only during periods of startup and shutdown of the IGCC unit, or when steam from the IGCC unit's heat recovery steam generator is unavailable. The following emission limitations shall apply:

1. NO_x emissions shall not exceed 0.16 lbs/MMBtu for oil firing.

2. Sulfur dioxide emissions shall be limited by firing low sulfur fuel oil with a maximum sulfur content of 0.05 percent by weight.

3. Visible emissions shall not exceed 20 percent opacity (except for one six-minute period per hour during which opacity shall not exceed 27 percent), while burning low sulfur fuel oil.

K. Performance Testing

Initial (I) compliance tests shall be performed on each turbine using both fuels. The stack test for each turbine shall be performed between 90-100 percent of the maximum heat rate input for the tested operating temperature. Annual (A) compliance tests shall be performed on each turbine with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using EPA reference methods in accordance with 40 CFR 60, Appendix A, as adopted by reference in Rule 17-297, F.A.C. and the requirements of 40 CFR 75:

1. Reference Method 5B for PM (I, A, for oil only)

2. Reference Method 8 for sulfuric acid mist (I, for oil only)

3. Reference Method 9 for VE (I, A)

4. Reference Method 10 for CO (I, A)

5. Reference Method 20 for NO_X (I, A)

6. Reference Method 18 for VOC (I, A)

7. Trace elements of Lead (Pb), Beryllium (Be) and Arsenic (As) shall be tested (I, for oil only) using Emission Measurement Technical Information Center (EMTIC) Interim Test Methods. As an alternative, Method 104 for Beryllium (Be) may be used; or Be and Pb may be determined from fuel analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

8. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I,A)

9. ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 for sulfur content of natural gas (I, and A if deemed necessary by DEP)

10. Reference Method 22 for fugitive emissions (I,A)

Other DEP approved methods may be used for compliance testing after prior Departmental approval.

L. Sulfur Content of Fuel

The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent by weight. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing for sulfur content of the fuel oil in the storage tanks once per day when firing oil. Testing for fuel oil heating value, shall also be conducted on the same schedule.

M. Monitoring Requirements

A continuous emission monitoring system (CEMS) shall be installed, operated, and maintained in accordance with 40 CFR 60, Appendix F, for each combined cycle unit to monitor nitrogen oxides and a diluent gas (CO_2 or O_2). The applicant shall request that this condition of certification be amended to reflect the Federal Acid Rain Program requirements of 40 CFR 75 when those requirements become effective within the State.

1. Each CEMS shall meet performance specifications of 40 CFR 60, Appendix B.

2. CEMS data shall be recorded and reported in accordance with Chapter 17-297.500, F.A.C., 40 CFR 60 and 40 CFR 75. The record shall include periods of startup, shutdown, and malfunction.

3. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

4. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of all CEMS.

5. For purposes of the reports required under this permit, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Specific Condition No. 10 herein, which exceeds the applicable emission limits in Specific Condition No. 7.

N. Notification, Reporting and Recordkeeping

To determine compliance with the syngas and fuel oil firing heat input limitation, the permittee shall maintain daily records of syngas and fuel oil consumption for each turbine and the heating value for each fuel. All records shall be maintained for a minimum of two years after the date of each record and shall be made available to representatives of the Department upon request.

O. Applicable Requirements

The project shall comply with all the applicable requirements of Chapter 17, Florida Administrative Code (F.A.C.) and 40 CFR 60 Subparts A and GG. The requirements shall include:

1. 40 CFR 60.7(a)(1) - By postmarking or delivering notification of the start of construction no more than 30 days

after such date;

2. 40 CFR 60.7(a)(2) - By postmarking or delivering notification of the anticipated date of the initial startup of each turbine and the auxiliary boiler not more than 60 days nor less than 30 days prior to such date;

3. 40 CFR 60.7(a)(3) - By postmarking or delivering notification of the actual startup of each turbine and the auxiliary boiler within 15 days of such date;

4. 40 CFR 60.7(a)(5) - By postmarking or delivering notification of the date for demonstrating the CEMSs performance, no less than 30 days prior to such date;

5. 40 CFR 60.7(a)(6) - By postmarking or delivering notification of the anticipated date for conducting the opacity observations no less than 30 days prior to such date;

6. 40 CFR 60.7(b) - By initiating a recordkeeping system to record the occurrence and duration of any startup, shutdown or malfunction of a turbine and the auxiliary boiler, of the air pollution control equipment, and when the CEMS is inoperable;

7. 40 CFR 60.7(c) - By postmarking or delivering a quarterly excess emissions and monitoring system performance report within 30 days of the end of each calendar quarter. This report shall contain the information specified in 40 CFR 60.7(c) and (d);

8. 40 CFR 60.8(a) - By conducting all performance tests within 60 days after achieving the maximum turbine and boiler firing rates, but not more than 180 days after the initial startup of each turbine and the auxiliary boiler;

9. 40 CFR 60.8(d) - By postmarking or delivering notification of the date of each performance test required by this permit at least 30 days prior to the test date; and

10. 17-297.345 - By providing stack sampling facilities for each turbine and the auxiliary boiler.

All notifications and reports required by this specific condition shall be submitted to the Department's Air Program, within the Southwest District Office. Performance test results shall be submitted within 45 days of completion of such test.

P. Submission of Reports

The following information shall be submitted to the Department's Bureau of Air Regulation within 12 months of issuance of this permit:

1. Description of the final selection of the turbines and the auxiliary boiler to be installed at the facility. Descriptions shall include the specific make and model numbers, any changes in the proposed method of operation, fuels, emissions or equipment.

2. Description of the CEMS selected. Description shall include the type of sensors, the manufacturer and model number of the equipment.

3. If construction has not commenced within 18 months of issuance of this permit, then the permittee shall obtain from DEP a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2)). Units to be constructed or modified in later phases of the project will be reviewed and limitations revisited under the supplementary review process of the Power Plant Siting Act.

Q. Protocols

The following protocols shall be submitted to the Department's Air Program, within the Southwest District Office, for approval:

1. CEMS Protocol - Within 60 days of selection of the CEMS, but prior to the initial startup, a CEMS protocol describing the system, its installation, operating and maintenance characteristics and requirements. The Department shall approve the protocol provided that the system and the protocol meet the requirements of 40 CFR 60.13, 60.334, Appendix B and Appendix F. This condition of certification shall be amended to reflect the Federal Acid Rain Program requirements of 40 CFR 75 when those requirements become effective within the State.

2. Performance Test Protocol - At least 90 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the Department's Air Program, within the Southwest District Office, a protocol outlining the procedures to be followed, the test methods and any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit. The Department shall approve the testing protocol provided that it meets the requirements of this permit.

R. Modifications

The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change.

XIV. SURFACE WATER DISCHARGES

Discharges into surface waters of the state during construction and operation of the project shall be in accordance with applicable provisions of Chapters 17-3, 17-4, 17-25, 17-28, 17-40, 17-160, 17-301, 17-302, 17-520, 17-522, 17-531, 17-532, 17-550, 17-551, 17-555, 17-560, 17-600, 17-601, 17-604, 17-640, 17-650, 17-660, 17-672, 17-699, and 17-701, Florida Administrative Code, and the following Conditions of Certification:

A. Plant Effluents and Receiving Body of Water

For discharges made from the PPS the following conditions shall apply:

1. Receiving Body of Water (RBW) - The receiving bodies of water have been determined by the DEP to be the reclaimed lake and subsequent down stream waters including Little Payne Creek, Payne Creek, and the South Prong Alafia River.

2. Point of Discharge (POD) - The point of discharge has been determined by DEP to be where the effluent from Outfall Serial Number 001 (OSN-001) physically enters the waters of the state in the reclaimed lake, or from OSN 002 to Payne Creek or from OSN 006 to the Alafia River from stormwater runoff collection systems.

3. From the issuance date of this permit through its expiration, the effluent from Outfall 001, shall not exceed the effluent limitations and shall be monitored by the permittee as specified below; if there is no discharge during a sampling period, the sample shall be collected on the day of next discharge. Outfall 001 wastewater sample shall be taken prior to actual discharging or mixing with the receiving waters. All samples shall be taken in strict accordance with the following table.

**EFFLUENT LIMITATIONS/
WATER QUALITY STANDARDS**

EFFLUENT CHARACTERISTIC	DAILY MINIMUM	30-DAY AVERAGE	DAILY MAXIMUM	SAMPLING FREQUENCY/TYPE
Flow (MGD)	N/A	Report	Report	Continuous/Recorder
Dissolved Oxygen (mg/l)[1]	5.0	Report	N/A	Daily/Grab
Total Ammonia (as N)(mg/l)*	N/A	Report	Report	2/Month/Grab
Un-ionized Ammonia (mg/l)*	N/A	Report	0.02	2/Month/Calculation
Specific Conductance (umhos/cm)***	N/A	Report	1275	Daily/Grab
Gross Alpha Particle Activity (pCi/l)	N/A	Report	15	2/Month/grab
Total Sulfate (mg/l)	N/A	Report	Report	2/Month/24-hr grab
pH (standard units)**	6.5	Report	8.5	Daily/Grab
Total Nitrogen (mg/l)*	N/A	Report	Report	2/Month/24-hr grab
Total Kjeldahl Nitrogen (mg/l)*	N/A	Report	Report	2/Month/24-hr grab
Total Suspended Solids (mg/l)	N/A	50	150	2/Month/24-hr grab
Water Temperature (°F)	N/A	Report	Report	Daily/Grab
$CBOD_5$ (mg/l)	N/A	1.0	3.0	2/Month/Grab

Total Residual Chlorine (mg/l)	N/A	Report	0.01	2/Month/Grab
ICP 23 metals (ug/l)	N/A	Report	****	2/year/Grab

* The permittee shall not exceed the background levels of this parameters, as specified in Table 3.5.1-2, submitted on 06/18/93.
** As per Rule 17-302.530 (52)(c), F.A.C.
*** As per Rule 17-302.530 (23), F.A.C.
**** Limits pursuant to rule 17-302.560, F.A.C.
1. The time and depth for sampling Dissolved Oxygen (DO) should be specified and recorded. DO monitoring should occur before 10:00 a.m. whenever possible.

B. Thermal Mixing Zone

The TECO is hereby granted a thermal mixing zone for the discharge from the cooling reservoir through Outfall 001 to the reclaimed lake. The mixing zone shall be a 250 foot radius semicircle centered at the point of entry into the reclaimed lake. The temperature at the edge of the mixing zone shall not exceed the limitations of Rule 17-302.520(4)(a), F.A.C., i.e. the temperature shall not exceed 92 degrees F nor 3 degrees F above ambient. The temperature at OSN 001 shall not exceed 92° F.

C. pH - The pH of the combined discharges to the cooling pond shall be such that the pH will fall within the range of 6.0 to 9.0 and any discharge from the pond at OSN 001 to the reclaimed lake shall not exceed 6.0 to 8.5.

D. Polychlorinated Biphenyl Compounds - There shall be no discharge of Polychlorinated biphenyl compounds.

E. Storm Water Runoff - During construction and operation discharge from the surface water management system from a storm event less than the once in 10 year, 24 hour storm shall meet the following limits and shall be monitored at all point source discharges through discharge structures, by a grab sample once per discharge, but not more often than once per week:

Effluent Characteristic	Discharge Limits Instantaneous Maximum
Flow (MGD)	Report
TSS (mg/l)	50
pH	6.0-8.5

1. During construction special consideration must be given to the control of sediment-laden runoff resulting from storm events. Best management practices erosion controls should be installed early during the construction period so as to prevent the transport of sediment into surface waters which could result in water quality violations and DER enforcement action. Revegetation and stabilization of disturbed areas

should be accomplished as soon as possible to reduce the potential for further soil erosion. Should construction phase runoff pose a threat to the water quality of state waters, additional measures such as treatment of imposed runoff or the use of turbidity curtains (screens) in on-site impoundments shall be implemented.

2. During plant operation, necessary measures shall be used to settle, filter, treat or absorb silt-containing or pollutant-laden storm water runoff to limit the suspended solids to 50 mg/l or less at OSN <u>002</u> and <u>003</u> during rainfall periods less than the 10-year, 24-hour rainfall.

3. Control measures shall consist at the minimum of filters, sediment traps, barriers, berms or vegetative planting. Exposed or disturbed soil shall be protected as soon as possible to minimize silt and sediment-laden runoff. The pH shall be kept within the range of 6.0 to 8.5 in the discharge to the cooling pond or OSN <u>002</u> and <u>003</u>.

F. Construction Dewatering

1. Discharge of construction dewatering to the cooling pond from outfall serial number **<u>004</u>** shall be limited and monitored as specified below:

Effluent Characteristic	**Discharge Limits**	**Monitoring Requirements**	
	Instantaneous Maximum	Measurement Frequency	Sample Type
Flow - m^3/day (MGD)	- Calculation	Daily	Totalizer
Turbidity (NTU)	-	1/week	grab
TSS mg/l	50.0	1/week	grab
pH	6.0-9.0	1/week	grab

2. Dewatering discharge descriptions - Dewatering water, outfall 004, includes all surficial groundwater extracted during all excavation construction on site for the purpose of installing structures, equipment, etc. Discharges to the cooling pond at a location to be depicted on an appropriate engineering drawing shall be submitted to DEP and SWFWMD. The Permittee shall report to DER the date that construction dewatering is expected to begin at least one week prior to the commencement of dewatering.

G. Steam System Blowdown

Blowdown discharge from the steam electric generating system to the cooling pond shall be limited and monitored at OSN 005 as specified below:

Effluent Characteristic	**Discharge Limits**		**Monitoring Requirements**
	Daily Maximum	**Sample Type**	**Measurement Frequency**
TSS (mg/l)	30.0	grab	1/month
Oil and Grease (mg/l)	15.0	grab	1/month
Flow (MGD)	--	Calculation	1/month

I. Stormwater Effluent Limits

From the issuance date of this permit through its expiration, the effluent from Outfall 002 shall not exceed the effluent limitations and shall be monitored by the permittee as specified below. A grab sample of the stormwater at the Outfall 002 is required to be analyzed bi-monthly for the following parameters:

EFFLUENT LIMITATIONS WATER QUALITY STANDARDS

Effluent Characteristics	**30-Day Average**	**Daily Maximum**	**Minimum**
Flow (MGD)	Report	Report	N/A
$CBOD_5$ (mg/l)	Report	12.0	N/A
Total Suspended Solids (mg/l)	Report	5.0	N/A
Specific Conductance (umhos/cm)	Report	1275*	N/A
Dissolved Oxygen (mg/l)	Report	N/A	5.0
pH (Std. Units)	N/A	8.5	6.5
Oil & Grease (mg/l)	Report	5.0	N/A

* As per Florida Administrative Code (F.A.C.), Rule 17-302.530 (23).

J. Surface Water Monitoring

1. Within ninety (90) days of issuance date of this certification the permittee must submit a proposed location for a compliance station at the end of the mixing zone. After receiving the Department's approval for this station, the permittee shall measure the water temperature, on a bi-weekly basis.

2. Based upon the results of the water quality reports (nutrients level only), the Department may require the permittee to prepare a Plan of Study to develop a Level II Water Quality Based Effluent Limitation (WQBEL) for the effluent at Outfall 001. Implementation of the cited study, after Department's approval is authorized in this certification.

3. Ninety (90) days from the issuance date of this certification, Tampa Electric Company (TECO) shall submit for Departmental approval a Biological Assessment Plan of Study (POS) for macroinvertebrates (using Hester-Dendy sampler and a ponar grab) for the receiving water body (the reclaimed lake). Upon approval of the (POS) by the Department, TECO will carry out this biological assessment once every three years, beginning three years after the first discharge from Outfall 001.

4. In order to provide the Department with reasonable assurance that the discharges from Outfall 001 does not violate the acute toxicity requirements of Section 17-302.500(d), F.A.C., the permittee shall perform the toxicity tests as specified below and submit the results to the Department for review.

a. The permittee shall initiate a series of bioassay tests, as described below, within 120 days from initiation of operations, to evaluate whole effluent toxicity of the discharge. All test species, procedures, and quality assurance criteria used shall be in accordance with <u>Methods for Measuring the Acute Toxicity of Effluents to Freshwater and Marine Organisms</u>, EPA/600/4-90/27. The permittee shall conduct a 96-hour static renewal acute toxicity test on the test species, <u>Ceriodaphnia dubia</u> and <u>Notropis leedsi</u>, twice a year (bi-annually) on samples of 100% whole effluent. Such static renewal tests will be conducted on four separate grab samples of 100% final effluent collected at evenly spaced (6-hour) intervals over a 24-hour period and used in four separate tests in order to account for daily variations in effluent quality.

A standard reference toxicant test shall be conducted concurrently with each species used in the toxicity test and all the test reports shall be submitted along with the concomitant monthly operation report.

b. If control mortality exceeds 10% of either species in any test, the test(s) for that species (including the control) shall be repeated. A test will be considered valid only if control mortality does not exceed 10% for either species. If, in any test, 100% mortality occurs prior to the end of the test, and control mortality is less than 10% at that time, that test including the control) shall be terminated with the conclusion that the sample demonstrates unacceptable acute toxicity.

c. If any screening test indicates that unacceptable toxicity (less than 80% survival of test organisms in 100% effluent) is found in any sample of effluent, additional acute (definitive) renewal toxicity testing involving the determination of 96-hour LC50 values with 95% confidence limits will be required. A minimum of three (3) such additional 96-hour tests are required to be conducted within 30 days from the date that any screening test indicates the presence of toxicity. Preferably, the first of these additional tests shall be initiated within 72 hours of a failed screening test. The second test shall be initiated at least seven (7) days after completion of the first additional test. Such tests shall be conducted using the test species which exhibited the most toxic response in the screening tests above, and shall be taken at the same time of day and day of the week during which the greatest toxic response was exhibited.

5. Characterization of the wastewater collected at the cooling pond system must be submitted, within ninety (90) days from initiation of operations. A composite sample of the wastewater must be analyzed for Primary and Secondary Drinking Water Parameters including radionucleides, Total Kjeldahl nitrogen, $CBOD_5$, and total ammonia.

6. **WQBEL Study Requirements**

If effluent Total Nitrogen concentrations for outfall 001 exceed the background levels of these parameters as specified in Table 3.5.1-2 of the SCA, TECO shall initiate a Level II Water Quality Based Effluent Limitation Study for the discharge from outfall 001. The study shall be conducted in accordance with the requirements of Rule 17-650, F.A.C.. TECO shall submit a draft plan of study (POS) for the study to the Point Source Evaluation Section within six months of notification by the Department that a study is necessary, and shall modify the POS as necessary to obtain Department approval.

The final POS shall include a schedule for the submittal of:

1) an Intensive Survey document summarizing all data collected, and
2) a WQBEL document summarizing all modeling conducted and proposed effluent limitations. The draft Intensive Survey document shall be provided within one year of the original POS submittal and the draft WQBEL document shall be provided within one and a half years of the original POS submittal.

XV. DOMESTIC WASTEWATER

A. Specific Conditions

1. No portion of the domestic wastewater collection system, treatment plant or effluent transmission line may be constructed without prior written approval from the Department. Construction of any portion of the domestic wastewater facility without the prior written approval of the Department will be considered a violation of the Conditions of Certification.

2. In order to obtain approval to construct a domestic wastewater treatment facility, the following forms, reports, plans and data, properly executed and appropriately signed and sealed by an engineer registered in the State of Florida must be submitted to the Department at least one hundred twenty (120) days prior to proposed date for commencement of construction:

a. The preliminary design report in accordance with Rule 17-600.715, F.A.C., (Minimum Class III Reliability features must be indicated. A Reduced Pressure Zone Backflow Preventer must be designated for potable water isolation.)

b. DEP Form 17-604.900(1), Application to Construct a Domestic Wastewater Collection System, with supporting documents.

c. DEP Form 17-600.910(1), Application to Construct a Domestic Wastewater Facility, with documentation.

d. DEP Form 17-640(1), Agricultural Use Plan, or DEP Form 17-640(2), Dedicated Disposal Site Plan, with documentation.

e. 8-1/2" x 11" copies of: (i) WWTP location, (ii) sludge disposal site, indicating all public or privatedrinking water wells within 0.5 miles, (iii) roadmap, or drawing of roads leading to the WWTP, (iv) flow process diagram, showing all piping, and planar and volumetric data.

3. All plans and proposals must comply with the requirements of the Departmental rules and regulations in effect as of the date of proposed commencement of construction. All requirements of Chapters 17-4, 17-600, 17-640 and other pertinent Florida Administrative Codes must be met, including construction certifications.

4. Department approval for construction of this domestic wastewater facility will be in effect for one (1) year from the date of issuance; request for extension of time must

be submitted in writing on forms and in a manner prescribed by the Department of Environmental Protection at least sixty (60) days prior to date of expiration of the construction approval.

5. Domestic wastewater post-certification approvals will be issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-3, 17-4, 17-300, 17-500 and the 17-600 Series. Tampa Electric Company (TECO) will be approved to perform the work or operate the facility shown on the approved drawing(s), plans, and other documents, attached thereto or on file with the Department.

6. In accordance with Chapter 17-699, F.A.C., the required certified operator on site time is:

A Class D or higher operator for three (3) non-consecutive visits per week for 1-1/2 hours per week. The Department reserves the right to modify staffing requirements.

7. The discharge from the chlorine contact chamber shall be sampled in accordance with Chapter 17-601, F.A.C. and shall meet the following limitations:

Parameter	**Unit**	**Min-imum**	**Maximum**	**Type Sample**	**Frequency**
Permitted Capacity (flow)	mgd	.000	0.010		Daily,5/wk
pH	STD UN	6.00	8.50	grab	Daily,5/wk
$CBOD_5$*& Total Suspended Solids*	mg/L	0	20 annual avg. 30 monthly avg. 45 weekly avg. 60 any one sample	grab	Monthly
Nitrate (as N)	mg/L	0	12	grab	Monthly
Cl_2	mg/L	0.5	-	grab	Daily,5/wk
Fecal coliform	#/100	0	200 annual avg. 200 monthly avg.	grab	Monthly

* Influent shall be monitored and reported monthly [Rule 17-601.300(1), F.A.C.]
The results shall be reported monthly on DEP Form 17-601.900(1).

8. The sludge shall be sampled after final treatment in accordance with Rule 17-640.700(1)(b) F.A.C. but prior to land application for the parameters listed below every six months. A copy of the analyses shall be submitted with the monthly operation report for the following parameters:

Total Nitrogen - % dry weight
Total Phosphorus - % dry weight
Total Potassium - % dry weight
Cadmium - mg/kg dry weight
Copper - mg/kg dry weight
Lead - mg/kg dry weight
Nickel- mg/kg dry weight
Zinc - mg/kg dry weight
pH - standard units
Total Solids - %

9. Direct discharge of effluent to waters of the state is not allowed. Such discharge shall be considered a violation of this certification and TECO shall immediately report any such discharge to the S.W. District Office.

10. TECO shall comply with all provisions of Chapter 17-640, F.A.C. and shall report any non-compliance or changes from the approved site plan to the Department.

11. TECO shall not place the treatment plant or effluent discharge system into service for any purpose other than testing for leaks and equipment operation prior to submittal of the engineer's certification and record drawings of the treatment plant and its disposal system.(Rule 17-600.710(3), F.A.C.)

12. Upon completion of construction and prior to placing the treatment plant or effluent discharge system into operation for any purpose other than testing for leaks and equipment operation, TECO shall submit a Notification That a Domestic Wastewater Facility Will Be Placed Into Operation [DEP Form 17-600.910(3)], signed and sealed by a Registered Engineer, to the DEP Southwest District Office.

13. TECO shall provide an approved flow measurement device on the sewage treatment plant to monitor the influent (ahead of any return flows) and/or effluent flow, as appropriate. The flow measurement device shall be calibrated at least annually, with evidence of calibration kept at the site of flow measurement, and submitted to the Department upon request.

14. TECO shall provide a weatherproof location for an on/site log book to monitor the daily activities of the certified operator. This log book shall record sign in/out times of the certified operator, list any maintenance performed and contain the signature and certification number of the operator.

15. TECO shall maintain all audible and visual alarm systems on the lift station(s) in operating condition at all times.

16. A reduced pressure zone backflow preventer shall be installed on any potable water supply pipeline connected to the treatment facility. No potable water outlet intended for human contact shall be located down-line of the backflow preventer.

17. The disinfection system shall be operated to maintain a minimum chlorine residual of 0.5 mg/L at the outfall from the chlorine contact chamber. A metering device for dosing chlorine to the effluent shall be utilized and the chlorine supply tank shall be inspected regularly to ensure proper operation.

18. Daily checks of the plant shall be performed by TECO or supplier, or his representative or agent five (5) days per week for all Class C and D plants pursuant to Rule 17-699.311(1), F.A.C.

19. TECO shall ensure that the construction and operation of this facility shall be as described in the application and supporting documents. Any request for changes to this approval shall be submitted in writing to the DEP Southwest District Domestic Wastewater Program Manager for review and clearance prior to implementation. Minor modifications will be considered for post-certification approval. Major modifications, such as selection of a different sanitary wastewater system alternative, will require submission of a completed application and appropriate processing fee for modification of these conditions of certification per Section 17-17, F.A.C.

B. General Conditions

1. The post-certification terms, conditions, requirements, limitations and restrictions are binding and enforceable pursuant to Sections 403.141, 403.161, 403.512, 403.514, 403.727, or 403.859 through 403.861, Florida Statutes. TECO is placed on notice that the Department will review this approval periodically and may initiate enforcement action for any violation of these conditions.

2. This approval is valid only for the specific processes and operations applied for and indicated in approved drawings or exhibits. Any unauthorized deviation from approved drawings, exhibits, specifications, or conditions of post-certification approval may constitute grounds for revocation and enforcement action by the Department.

3. As provided in subsections 403.087(6), 403.511, and 403.722(5), F.S., the issuance of post-certification approval does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, State, or local laws or regulations. Post-certification approval is not a waiver of or approval of any other Department approval that may be required for other aspects of the total project which are not addressed in this section.

4. Post-certification approval conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. Post-certification approval does not relieve the TECO from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of the approved source, or from penalties therefore; nor does it allow the TECO to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. TECO shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the TECO to achieve compliance with the conditions of this certification, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions and when required by Department rules.

7. If, for any reason, TECO does not comply with or will be unable to comply with any condition or limitation specified in post-certification approval, TECO shall immediately provide the Department with the following information:

a) A description of and cause of noncompliance; and,

b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance. TECO shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of post-certification approval.

8. In accepting this certification, TECO understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this approved source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the approved source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

9. This certification or a copy thereof shall be kept at the work site of the approved activity.

10. TECO shall comply with the following:

a) Upon request, TECO shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) TECO shall hold at the facility or other location designated by this certification records of all required monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation), reports, and records of all data used for post-certification approval. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. the date, exact place, and time of sampling or measurements;

2. the person responsible for performing the sampling or measurements;

3. the dates analyses were performed;

4. the person responsible for performing the analyses;

5. the analytical techniques or methods used; and,

6. the results of such analyses.

11. When requested by the Department, TECO shall within a reasonable time furnish any information required by law which is needed to determine compliance with the approval. If TECO becomes aware the relevant facts were not submitted or were incorrect in the siting certification application or in any post-certification report to the Department, such facts or information shall be corrected promptly.

XVI. DRINKING WATER FACILITIES

A. Prior Approval

1. No portion of the potable water supply system or any portion of a water supply system that will be or is intended to be converted to potable water use at a later date may be constructed without prior written approval from the Department. Construction of any portion of the potable water supply system without the prior written approval of the Department will be considered a violation of the Conditions of Certification. Reference: F.A.C. Rules 15-555.350, .520(1), and (2).

2. In order to obtain approval to construct a potable water supply system which includes an on-site water treatment facility, the following information must be submitted to the Department no earlier than one year prior to the date that the water supply system is proposed for construction:

a. A completed and fully executed "Application to Construct a Public Drinking Water System" form which complies with the requirements of the rules and regulations of the Department in effect as of the date that the request for approval to commence construction of the system is made to the Department. Reference: F.A.C. Rules 17-4.050 and 17-555.500 and .520.

b. Copy of the well driller's well completion report for each well to be used as a potable water supply well. Reference: F.A.C. Rules 17-4.050 and 17-555.315, .520, and .530.

c. Complete water quality analysis of the raw water from each individual well to be used as a potable water supply well. Analysis of composite samples will not be accepted. The analysis must include all water quality parameters required for the classification of the water supply system being proposed pursuant to the rules and regulations of the Department in effect as of the date that the request for approval to construct the system is made to the Department. Each individual analysis must have been performed by a laboratory certified by the State to perform that particular potable water quality analysis and must have an analysis date within one (1) year of the date that the request for approval to construct the water supply system is made to the Department. Reference: F.A.C. Rules 17-4.050, 17-555.520 and .530 and 17-550.200(43), .300, .330, .400, .521(3), .550(3)(e), and .730(1) and (2).

d. Complete specifications for the material and workmanship for the entire potable water supply system for which the request for approval to construct is being made. The specifications must be signed and sealed by an engineer registered in the State of Florida and must provide documentation that the material and workmanship will comply with all applicable rules and regulations of the Department in effect as of the date that the request for approval to construct is made to the Department. Reference: F.A.C. Rules 17-4.050, 17-555.520 and .530, and 21H-23.

e. Complete engineering drawings of the entire proposed potable water supply system for which approval to construct is being requested. The drawings must demonstrate full compliance with all applicable rules and regulations of the Department in effect as of the date that the request is made to the Department for approval to construct the system. The drawings must be signed and sealed by an engineer registered in the State of Florida. Reference: F.A.C. Rules 17-4.050, 17-555.520 and .530, and 21H-23.

f. Site plan showing the location of each potable water supply well. The site plan must include all proposed and existing, above and below grade, facilities, natural formations (e.g. streams, creeks, etc.), structures, etc. within a minimum of a complete five hundred (500) foot radius of each well head; however, if any facility, natural formation, structure, etc. is located outside of the five hundred (500) foot radius and that facility, natural formation, structure, etc. has a setback distance from the well head greater than five hundred (500) feet established in applicable rules of the Department in effect as of the date that the request for approval to construct is made, then that facility, natural formation, structure, etc. must also be shown on the site plan requested here. The site plan must be certified for accuracy by the professional engineer registered in the State of Florida responsible for design of the potable water supply system. F.A.C. Rules 17-4.050, 17-555.312, .520, and .530, and 21H-23.

g. Signed and sealed comprehensive engineering report on the proposed potable water supply system which fully describes the project and basis of design. The report must include design data and such pertinent data to give an accurate understanding of the work to be undertaken and must provide supporting documentation that the potable water system as proposed will comply with all applicable rules and regulations of the Department in effect as of the date that the request for approval to construct the water supply system is made to the Department. Reference: F.A.C. Rules 17-4.050, 17-555.520 and .530, and 21H-23.

3. In order to obtain approval to construct a water supply system where the potable water is to be supplied by an off-site public water supply system, the following information must be submitted to the Department no earlier than one (1) year prior to the date that the water supply system is proposed for construction: