TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power and Light Company (FPL)
Cape Canaveral Energy Center

Cape Canaveral Plant Conversion Project
Construction of one Nominal 1,250-Megawatt (MW) Combined Cycle Unit
Shutdown and Dismantlement of two Residual Oil and/or Gas-fueled Steam Generating Units

Brevard County

DEP File No. 0090006-005-AC

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation

March 13, 2009

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

Processing Schedule

- December 30, 2008: Received Air Construction Permit Application
- February 11, 2009: Received Supplemental Information
- March 13, 2009: Preliminary Determination Issued

Facility Description and Location

FPL proposes to shut down and dismantle the two 400 MW residual oil and/or gas-fueled steam generating units and to construct a nominal 1,250 MW natural gas-fueled combined cycle unit at the Cape Canaveral Plant (CCP) site. The CCP site will be renamed the Cape Canaveral Energy Center (CCEC).

The CCP location is at 6000 North U.S. Highway 1 between Cocoa and Titusville in Brevard County. The location with respect to other FPL facilities in Florida is shown in Figure 1. The plant is bounded on the east by the Indian River Lagoon which is part of the Intracoastal Waterway. Figure 2 is an aerial view of the existing CCP taken from the southwest.

Figure 1. Cape Canaveral Plant in FPL System and Location of Plant in Brevard County.

The plant is located approximately 185 kilometers (km) east of the Prevention of Significant Deterioration (PSD) Class I Chassahowitzka Wilderness Area. The facility UTM coordinates are Zone 17, 523.1 km East and 3,149 km North.

REGULATORY CLASSIFICATION

The CCP is a "Major Stationary Source" as defined in Rule 62-210.200, Florida Administrative Code (F.A.C.). The CCEC project does not trigger the rules for the Prevention of Significant Deterioration (PSD) pursuant to Rule 62-212.400, F.A.C. and does not require a best available control technology (BACT) determination.

The CCEC will be a Title V or "Major Source" of air pollution in accordance with Chapter 213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year (TPY). Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC) and sulfuric acid mist (SAM).

The CCEC will be subject to several subparts under 40 Code of Federal Regulations (CFR), Part 60 – Standards of Performance for New Stationary Sources (NSPS).

Unit 3 is subject to 40 CFR 60, Subpart KKKK – NSPS for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also applies to duct burners (DB) that are incorporated into combined cycle projects.

Emergency generators and a diesel fire pump will be subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines.

Natural gas compressors will be subject to 40 CFR 60, Subpart JJJJ – NSPS for Stationary Spark Ignition Internal Combustion Engines.

A temporary natural gas-fueled boiler will be subject to 40 CFR 60, Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units.

An auxiliary boiler and process (fuel) heaters will be subject to 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial-Commercial-Institutional Steam Generating Units.

The CCEC will be a minor (area source) of hazardous air pollutants (HAP). The CCEC will include emission units that will be subject to certain area source provisions of 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP).

Natural gas compressors will be subject to 40 CFR 63, Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE).

The CCEC will operate units subject to the Title IV Acid Rain provisions of the Clean Air Act (CAA).

The CCEC is subject to the Clean Air Interstate Rule (CAIR) in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.

The project is subject to certification under the Florida Power Plant Siting Act, 403.501-518, Florida Statutes (F.S.) and Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The two existing 400 MW steam generating units are scheduled to be shutdown and then dismantled by April 1, 2010. There will be no overlap of operation between the existing units and the new proposed units, which are anticipated to have an in-service date of June 2013.

The CCEC project includes the construction of a natural gas-fueled 3-on-1 combined cycle unit with a nominal rating of 1,250 megawatts (MW) referenced to International Standards Organization (ISO) conditions of 59 °F and standard humidity and pressure. The combined cycle Unit 3 will consist of: three nominal 265 MW combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems and a common nominal 500 MW steam turbine-electrical generator (STG); three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors and a nominal 428 million Btu/hour, lower heating value (mmBtu, LHV) gas-fired DB with three 149 foot exhaust stacks.

FPL is considering three different models of the Mitsubishi Power Systems (MPS) G Class CTG. These include the MPS 501G1, the MPS 501G1+, and the MPS 501G3. FPL is also considering the recently developed Siemens H CTG. The latter would need to be resized (from the European version) and optimized for the 60-hertz (Hz) U.S. market. The final rating of the selected MPS or Siemens model will be between 250 and 280 MW at ISO depending upon the model selected.

Additional ancillary equipment will include:

- One nominal 85,000 pounds of steam per hour (lb/hr) auxiliary boiler;
- Two nominal 10 mmBtu/hr natural gas fired fuel heaters (one is a spare);
- Seven nominal natural gas-fueled gas compressors, each rated at approximately 1,340 hp;
- Two nominal 2,250 kilowatts (kW) diesel-fueled emergency generators;
- One nominal 300 horsepower (hp) diesel-fueled fire pump engine; and
- One nominal 110 mmBtu/hr boiler for the construction phase.

Following is a listing of the new emissions units for the proposed project.

ID	Emission Unit Description
006	Unit 3A – one nominal 265 MW CTG with supplementary-fired HRSG
007	Unit 3B – one nominal 265 MW CTG with supplementary-fired HRSG
008	Unit 3C – one nominal 265 MW CTG with supplementary-fired HRSG
009	One nominal 85,000 pounds per hour (lb/hr) auxiliary boiler (99.8 mmBtu/hr)
010	Two nominal 10 mmBtu/hr gas-fired process heaters (one is a spare)
011	Seven nominal 1,340 hp natural gas compressors
012	Two nominal 2,250 kW emergency generators
013	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank
014	One 110 mmBtu/hr boiler to be used only under the construction phase

Following are additional project characteristics.

- Fuels: Each CTG will fire natural gas as the primary fuel and ultra low sulfur diesel (0.0015% sulfur) fuel oil (ULSD FO) as a restricted alternate fuel. The applicant requests an equivalent of 1,000 hours per year per CTG for oil firing. The three CTG could cumulatively fire up to 3,000 hours per year of fuel oil. The ULSD FO will be stored in the existing north fuel oil storage tank.
- Generating Capacity: Each of the three CTG has a nominal generating capacity of 265 MW. Each of the three HRSG provides steam to the single STG, which has a nominal capacity of 500 MW. The nominal capacity of Unit 3 will be 1,250 MW.
- Controls: CO, $PM/PM_{10}/PM_{2.5}$ and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and ULSD FO. NO_X emissions will be reduced with dry low-

NO_X (DLN) combustion technology for gas firing and wet injection (WI) for oil firing. In combination with these NO_X controls, a SCR system further reduces NO_X emissions during combined cycle operation.

- Continuous Monitors: Each CTG is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitors as well as CO monitors are employed for demonstration of continuous compliance with certain emission limits that insure the project will not be a major stationary source modification with respect to the PSD rules. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: Each HRSG has a combined cycle stack that is at least 149 feet tall with a nominal diameter of 22 feet. The following table summarizes the nominal exhaust characteristics of a representative CTG/HRSG set, exclusive of the DB:

Table 1. Exhaust Characteristics of the CTG comprising Unit 1 at 100% Load and 59 °F

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp., °F	Exhaust Temp., °F	Flow Rate ACFM
Gas	2,406 mmBtu/hour *	59 °F	195 °F	1,388,967
Oil	2,268 mmBtu/hour *	59 °F	357 °F	1,677,310

* The Department will set a maximum heat input rate at a higher value in the expectation that the delivered products may achieve a greater (or lower) heat input rate than the nominal value.

The following figure includes an aerial photograph from the FPL website of the two existing steam generating units and their 397-foot stacks taken from southwesterly direction. The other graphic is an artist rendition of the combined cycle unit after dismantling of the existing stacks and units and completion of the proposed project.

Figure 2. FPL Cape Canaveral Units 1 and 2. Artist Rendition of New Combined Cycle Unit

The shut down and dismantlement of the two units will be quite noticeable as they are presently allowed to be fueled by up to 2.5 percent (%) sulfur residual fuel oil augmented by natural gas. Also, the existing units are subject to a 40% visible emissions (VE) standard and are allowed even greater opacity during soot blowing. By contrast, the new unit will use inherently clean fuels and will typically exhibit zero VE.

Process Description

A CTG is an internal combustion engine that operates with rotary rather than reciprocating motion and that is coupled to an electrical generator. A representative longitudinal section diagram of a

CTG, in this case for a MPS 501G (rotor inside of casing) from a MPS brochure, is shown in the left hand side of the figures below. The photograph on the right hand side of the figure is of a Siemens H-Class CTG that is undergoing validation testing in Germany. The view is from the rotor section looking into the combustor section (without the cans). A similar product but smaller product will be developed for the 60 megahertz U.S. market.

Ambient air is drawn into the multistage compressor of the CTG where it is compressed to a very high pressure ratio. The compressed air is then directed to the combustor section, which consists of individual steam-cooled, can-annular, DLN combustors. Fuel is introduced, ignited, and burned. The combustor outlet temperature is greater than 2,700 ºF.

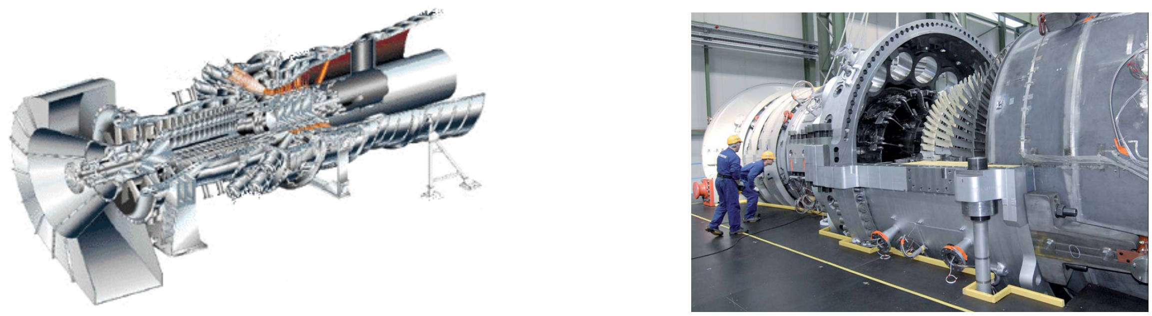


Figure 3. Longitudinal View of MPS 501G, Siemens "H" Class CTG (MHI, Siemens Websites)

The hot combustion gases routed through the steam-cooled transition pieces then are diluted with additional cool air from the compressor and directed to the turbine (expansion) section. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas (TEG) is discharged at a temperature greater than 1,125 ºF and contains more than 10% oxygen (O_2). The TEG is available for additional energy recovery and can also support further combustion.

Each CTG/HRSG set will operate in combined cycle mode as depicted in Figure 4. The TEG from each CTG will raise additional steam in each HRSG. The steam from the three HRSG will, in-turn, drive a single, separate STG producing additional electrical power.

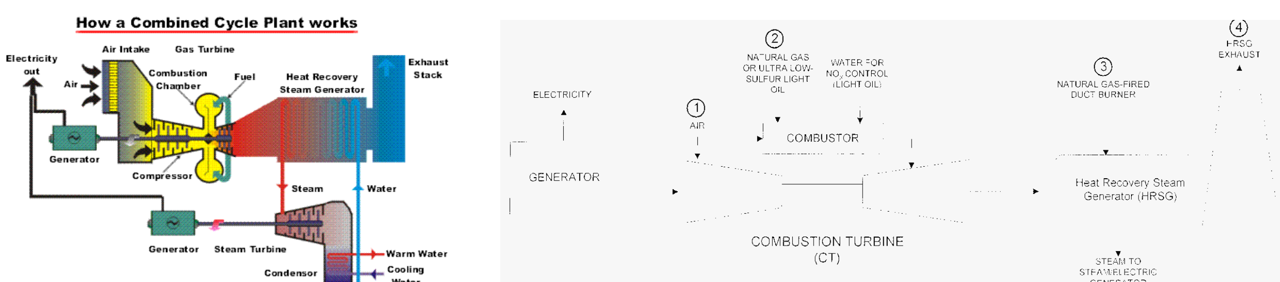


Figure 4. Natural Gas Fueled Combined Cycle Unit with DB and Backup ULSD FO

In combined cycle mode, the thermal efficiency of the most modern MPS G-Class CTG is approximately 58 percent (%) on the basis of LHV and about 53% based on the higher heating value (HHV). The Siemens H-Class CTG is expected to achieve approximately 60% thermal efficiency on the basis of LHV.

- Inlet Conditioning: Evaporative cooling is the injection of fine water droplets into the CTG compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a higher mass flow rate through the CTG with a boost in electrical power production. The emissions performance remains within the normal profile of the CTG for the lower compressor inlet temperatures. This is typically implemented at ambient temperatures of 60° F or higher.

- Duct Burning: Gas-fired DB can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2,880 hours of duct burning per year for each HRSG.

3. RULE APPLICABILITY

State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the Florida Administrative Code.

Table 2. Key Applicable State Regulations

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Federal Regulations

This project is also subject to the following federal provisions regarding air quality as established by the U.S. Environmental Protection Agency (EPA) in the CFR.

Table 3. Key Applicable Federal Regulations

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 63	National Emission Standards for Hazardous Air Pollutants (NESHAP)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain - Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions
Part 96	NO_X Budget Trading Program for State Implementation Plans

Description of PSD Non-Applicability

The Department regulates major air pollution sources in accordance with Florida's PSD program, as described in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant.

The CCP is a Major Stationary Source with respect to the PSD Rules because it is a fossil fuel-fired steam electric plant of more than 250 million Btu heat input and has the potential to emit 100 tons per year or more of a PSD pollutant.

The CCEC Project is not a Major Modification of a Major Stationary Source because there will not be a net emissions increase greater than the significant emission rate (SER) of a PSD pollutant. The SER means a rate of pollutant emissions that would equal or exceed: 100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC; 25 TPY of particulate matter (PM); 15 TPY of PM smaller than 10 microns (PM_{10}); 7 TPY of SAM; or 0.6 TPY of lead (Pb).

Estimates of Net Emissions Changes

The new combined cycle unit will result in emissions of CO, NO_X, SO_2, PM/PM_{10}, SAM and VOC. The shut down and dismantlement of the two residual oil- and/or gas-fueled steam generating units will result in net emission changes of the same pollutants that are less than the SER.

The following table is a summary of the emissions increases and decreases from the proposed CCEC project to determine which pollutants will be emitted in excess of their respective SER.

Table 4. Applicant's Summary of Net Emissions Changes and PSD Applicability for the FPL CCEC Project.

Pollutant	CCP Baseline Emissions TPY	CCEC Potential Emissions TPY	Net Emissions Increases (Decreases) TPY	PSD SER TPY	PSD?
SO_2	11,140	203	(10,937)	40	No
PM/PM_{10}	918/918	189/189	(729)/(729)	25/15	No
NO_X	7,725	506	(7,219)	40	No
CO	703	533	(170)	100	No
VOC	68.4	103.8	35.4	40	No
SAM	495	41	(454)	7	No
Lead	0.11	0.05	(0.06)	0.6	No
HAP	>25	<20	(≥ 5)	Not applicable (NA)	NA

Although no historical estimates of HAP are provided, the CCP is a major source of HAP according to previous applications submitted by FPL and permits issued by the Department. The switch from residual fuel oil to inherently clean fuels through the CCEC project will reduce emissions of nickel (a HAP) and vanadium (V, not classified as a HAP) that tend to catalyze the oxidation of SO_2 to SAM. The future CCEC will not be a major source of HAP.

4. DRAFT OF EMISSIONS STANDARDS

4.1 NO_X Emissions Standard

NO_X Formation

NO_X forms in the CTG combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. It also forms by oxidation of nitrogen present in the fuel.

Thermal NO_X. Thermal NO_X forms in the high temperature area of the CTG combustor as seen on the left hand side of Figure 5.

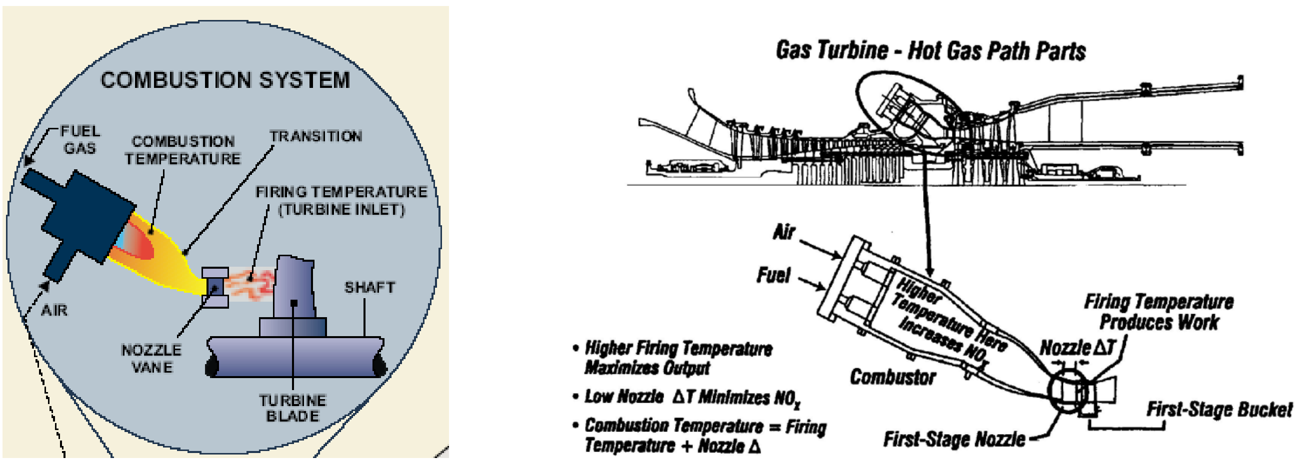


Figure 5. Relation between Combustion and Firing Temperatures and NO_X Formation

Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The relationship between flame and firing temperature, output and NO_X formation are depicted in the right side of Figure 5, which is from a GE discussion on these principles.

In all but the most recent CTG combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle.

Uncontrolled emissions can range from about 100 to over 600 parts per million by volume, dry, corrected to 15% O_2 (ppmvd @15% O_2) depending upon design. The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 from the CTG chosen for this project.

Descriptions of Available NO_X Controls

Diluent Injection: WI. Injection of either water or steam as a diluent directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the CTG.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_X emissions in the range of 30 to 42 ppmvd when employing WI for backup ULSD FO firing. WI results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis for further reduction to BACT limits by other techniques as discussed below.

CO and VOC emissions are relatively low for most CTG. However, WI may increase emissions (water more than steam) of both of these pollutants.

Combustion Controls: DLN. The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones. These principles are incorporated into the M501G DLN combustor (the Siemens H DLN combustor would be similar) shown on the left hand side of Figure 6. There is a central diffusion pilot nozzle that provides stability but ultimately limits the ability of the combustor to achieve the lowest possible NO_X emissions without further control.

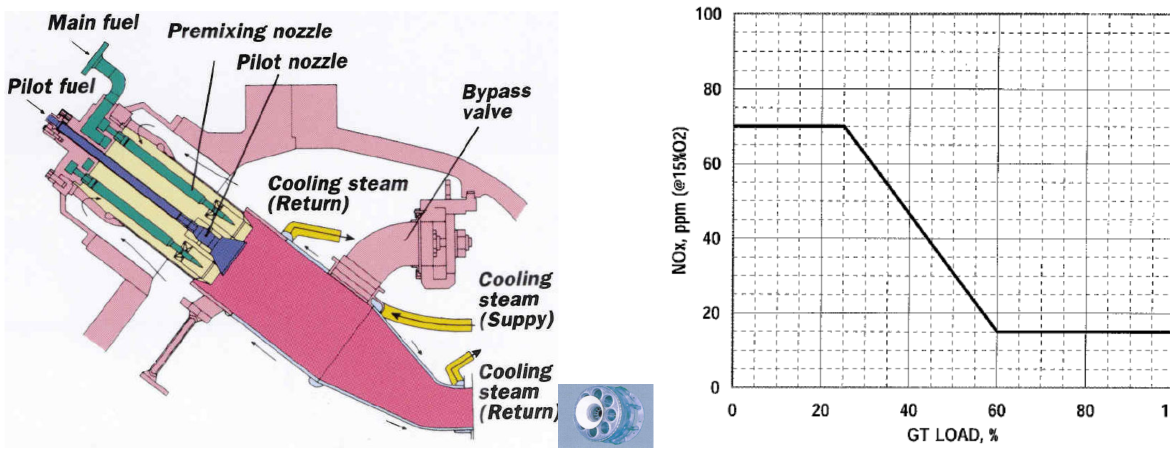


Figure 6. M501G DLN Combustor, Nozzle Block and NO_X versus Load Specification

The graph on the right hand side in Figure 6 contains the NO_X specifications for new Mitsubishi M501G1 CTG. The combustor emits NO_X at concentrations less than 15 ppmvd at loads between 60 and 100 percent of capacity. The firing temperature within the 60-100% load range is between roughly 2500 and 2750 °F. The low NO_X values are an excellent achievement considering the high firing temperature.

The difference between combustion temperature and firing temperature into the first stage is minimized by steam cooling of the transition piece and first stage nozzle. Thus a lower combustion temperature (and lower NO_X) can be achieved by steam cooling compared with air cooling for a given firing temperature (equal work). Alternatively, a higher firing temperature (more work, greater efficiency) can be achieved by steam cooling compared with air cooling for a given combustion temperature (equal NO_X).

The combustor for the M501G can probably achieve low NO_X emissions (< 20 ppm) at lower load than suggested by the diagram. The tendency to increase NO_X concentrations is mitigated by decreasing firing temperature.

Selective Catalytic Reduction (SCR). Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the CTG. SCR reduces NO_X emissions by injecting ammonia (NH_3) into the flue gas in the presence of a catalyst. NH_3 reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water according to the following simplified reaction:

The left hand side of Figure 7 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the NH_3 injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met.

The right hand side of Figure 7 is a photograph of the FPL WCEC Unit 1 Power Block. The external lines to the NH_3 injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

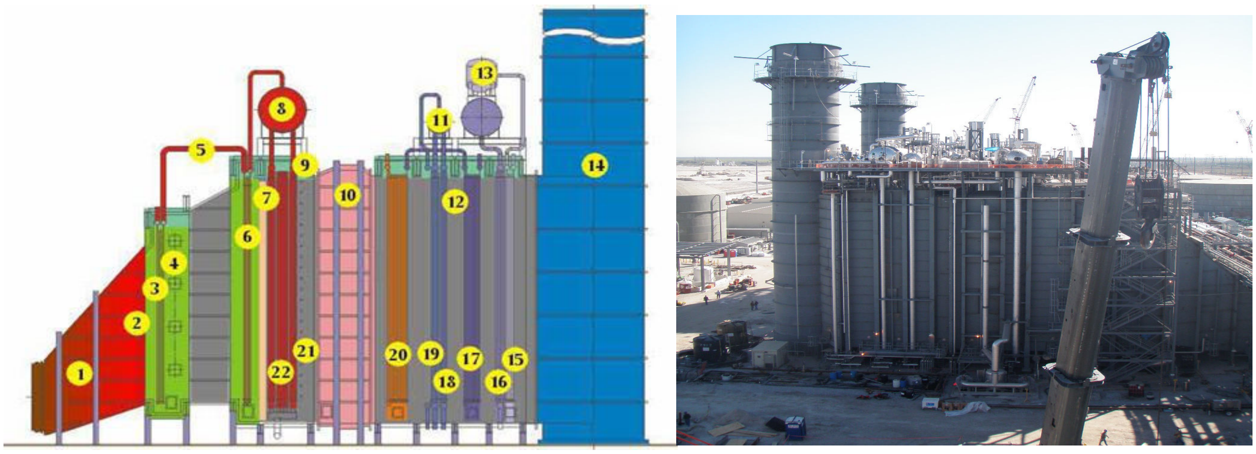


Figure 7 – Key HRSG Components (10 is SCR), FPL West County Energy Center Unit 1

The SCR catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive NH_3 use can increase emissions of CO, NH_3 (slip) and $PM_{10}/PM_{2.5}$ when sulfur-bearing fuels are used.

Applicant's NO_X Emissions Standard Proposal

The applicant proposes a NO_X limit of 2.0 ppmvd @15% O_2 for Unit 3 as a 30-unit operating day rolling average with compliance by CEMS whether or not the DB are in use. FPL proposes to meet the emission limit while burning natural gas by a combination of DLN technology and SCR. FPL proposes a NO_X emission limit of 8 ppmvd @15% O_2 by a combination of wet injection and SCR while burning backup ULSD FO. The corresponding standards pursuant to 40 CFR 60, Subpart KKKK are 15 and 42 ppmvd @15% O_2, on a 30-unit operating day rolling basis.

Department's Draft NO_X Emissions Standard Determination

The applicant's proposed limits are acceptable to the Department. These limits will insure compliance with Subpart KKKK and that the CCEC project will not trigger PSD and a BACT determination.

4.2 CO and VOC Emissions Standard

CO and VOC Formation and Combustor Characteristics

CO and VOC are emitted from CTG due to incomplete fuel combustion. Most CTG incorporate good combustion to minimize emissions of CO and VOC. The primary control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of an oxidation catalyst.

The figure below contains CO specifications for the M501G while firing natural gas and FO, including the guarantee values that apply between 60 and 100%.

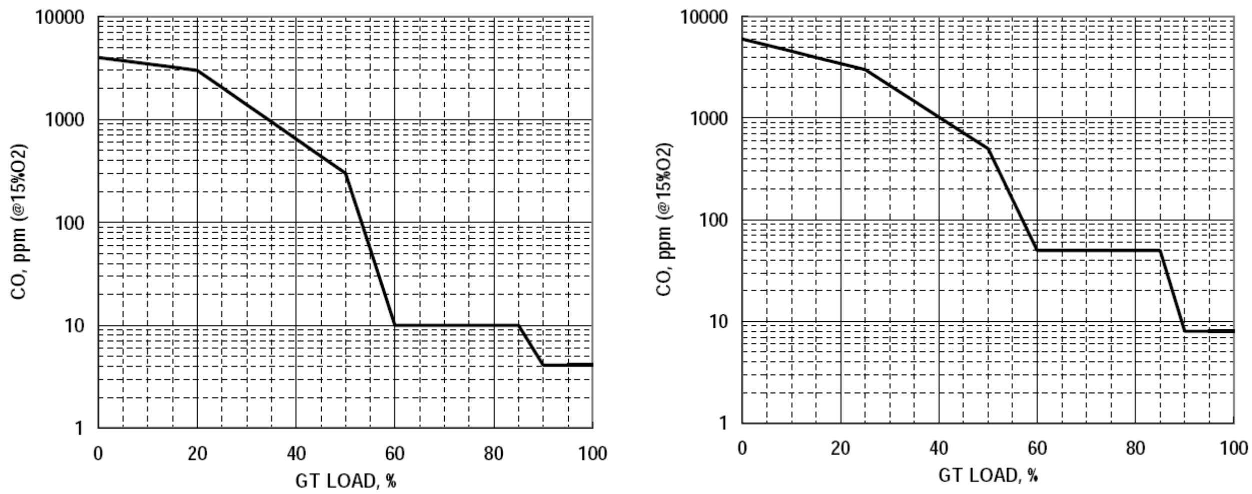


Figure 8. Expected CO versus Load while burning Gas or FO in a M501G

Generally the performance data on the left hand side indicate that the combustor performs very well on natural gas within the range of 60 to 100% of full load. At 60% of full load the flame and firing temperatures are great enough to destroy almost all CO. The graph on the right shows the characteristics while firing FO.

Typically, VOC concentrations are an order of magnitude less than CO concentrations. Therefore, while burning natural gas, VOC emissions will likely be less than 1 ppm while operating between 60 and 100% of full load. Similarly, VOC emissions less than 5 ppm and as low as 1 ppm are expected while firing FO.

DB and FO Considerations

The presence of a DB (refer to Figure 7, Component 4) complicates the evaluation somewhat. Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (~1,200 ^{o}F) and high excess air (> 12% O_2). In the design shown in Figure 7, some of the heat is used by a high pressure superheater (Component 3). The gas-fired DB (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6). Figure 9 shows an individual burner and an array comprising a DB. The hot TEG serves as combustion air for gas introduced into the burner array.

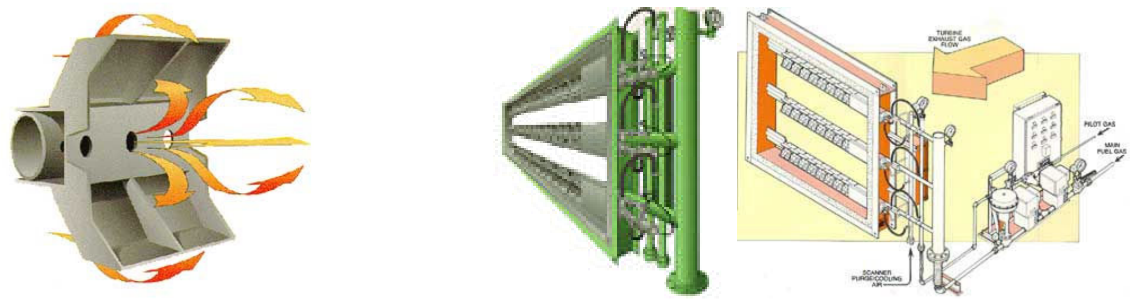


Figure 9 – Individual Burner and Array within Supplementary-Fired HRSG (Coen)

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 ^{o}F. VOC such as ethane and propane ignite at temperatures less than 900 ^{o}F. All of the necessary conditions are present to minimize further CO and VOC concentration increases when corrected to 15% oxygen.

CO emissions while firing FO should be very low, again, based on the high combustion temperature and the relatively high temperature and excess air in the TEG.

<u>FPL's CO and VOC Emissions Standard Proposal</u>

FPL has proposed emission limits for CO, VOC and PM/PM_{10}/$PM_{2.5}$ as the use of good combustion controls while firing natural gas or ULSD FO in accordance with the defined operating hours for each fuel. FPL proposes the emissions limits given in Table 5 for CO and VOC to account for all of the scenarios discussed above.

Table 5. FPL Emission Standard Proposal for CO, VOC – CCEC Project **(ppmvd@15% O_2)**

Modes (at full load)	**CO**	**VOC**
Natural Gas	5.0	1.5
Natural Gas & DB	7.6	1.9
ULSD FO	10.0	6.0

FPL obtained high load (90-100%) guarantees of 5.0 and 10.0 ppmvd CO @15% O_2 for natural gas and FO firing, respectively.

<u>Department's Draft CO and VOC Emissions Standard Determination</u>

FPL initially requested annual compliance tests to demonstrate compliance with the standards given above. However, to provide reasonable assurance that that the CCEC project will not trigger PSD for CO, the Department determined that CEMS are required and that a 30-unit operating day rolling average is appropriate.

The Department will set a CO limit of 8.0 ppmvd @15% O_2 for Unit 3 as a 30-unit operating day rolling average with compliance by CEMS while firing natural gas whether or not the DB are in use. The main consideration for this value is the medium load performance (60 to 85% of full load) as shown in Figure 8 above. The Department will set a similarly based CO emission limit of 10 ppmvd @15% O_2 while burning backup ULSD FO.

Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds.

A permit condition requires that FPL shall design and build the project to facilitate possible future installation of an oxidation catalyst system to control CO emissions from each CTG/supplementary-fired HRSG.

4.3 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) Emissions Standard

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for CTG contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution.

For this project the applicant has proposed the use of ULSD FO (0.0015 percent sulfur) and clean natural gas with a sulfur fuel specification less than or equal to 2 grains of sulfur per 100 standard cubic feet of natural gas ($\leq$ 2 gr/100 SCF).

FPL estimated 210 tons per year of SO_2 and 42 tons per year of sulfuric acid mist (SAM) for CCEC Unit 3. Realistically, annual emissions will be approximately one-fourth of the estimated values because the sulfur concentration in the pipeline gas is typically closer to 0.5 gr/100 SCF than to 2 gr/100 SCF.

Department's Draft SO_2 Emissions Standard Determination

The Department accepts FPL's emission limit proposal for SO_2 and SAM.

The Subpart KKKK Limit for SO_2 is 0.060 lb SO_2/mmBtu heat input. Compliance can be demonstrated by the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content is 0.05 weight percent or less for oil and less than 20 gr/100 SCF for gas. The applicant's sulfur emission standard proposal for this project will easily insure compliance with Subpart KKKK and that net SO_2 and SAM emissions increases will be less than the respective significant emission rates.

4.4 Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Emissions Standard and Ammonia (NH_3) Control

PM/PM_{10} $PM_{2.5}$ Formation and Control Options

PM, PM_{10} and $PM_{2.5}$ will be emitted from the CTG and DB due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ULSD FO will be efficiently combusted at high temperature in the CTG and DB and will be the only fuels fired in the proposed unit. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The ULSD FO to be combusted contains a minimal amount of ash and will be limited to less than an equivalent of 1,000 hours per CTG per year making any conceivable add-on control technique for $PM/PM_{10}/PM_{2.5}$ either unnecessary or impractical.

Other $PM/PM_{10}/PM_{2.5}$ Considerations

NH_3 Slip and Ammonium Salts Formation: Emissions of NO_X, SO_2, and SAM are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. These constituents form the fine PM that comprises $PM_{2.5}$. $PM_{10}/PM_{2.5}$ emissions can be increased due to the formation of these ammonium salts prior to exiting the stack or in the environment and contribute to regional haze. It is important to limit NH_3 emissions (known as slip) originating from the SCR NO_X control technology. Elevated levels of NH_3 slip can also be an indication of a degrading catalyst.

Applicant's $PM/PM_{10}/PM_{2.5}$ Proposal

FPL proposes $PM/PM_{10}/PM_{2.5}$ emissions standard as an opacity limit of 10% in conjunction with the use of inherently clean fuels.

Department's Draft $PM/PM_{10}/PM_{2.5}$ Emissions Standards

The following conditions are established as the draft emissions standards.

- The CTG shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The DB are limited to firing only natural gas meeting this specification. The CTG may fire ULSD FO as a restricted alternate fuel to an equivalent of 1,000 hours per CTG per year or a total of 3,000 hours for the three CTG per year, which shall contain no more than 0.0015% sulfur by weight.
- VE shall not exceed 10% opacity based on a 6-minute average.
- NH_3 emissions (slip) shall not exceed 5 ppmvd.

4.5 Department Draft Emissions Standards for CTG and DB

Emissions from each CTG shall not exceed the values given in the following table.

Table 6. Draft Emissions Standards

Pollutant	Fuel	Method of Operation	Initial Stacks Tests		CEMS Rolling Average Limit ppmvd [a]
			ppmvd [a]	lb/hr [b]	
CO [d]	Oil	CTG	10.0	61.0	10.0, 30 unit operating days [c,d]
	Gas	CTG & DB	7.6	52.7	8.0, 30 unit operating days [c,d]
		CTG Normal Mode	5.0	29.0	
NO_X [e]	Oil	CTG	8.0	80.0	8.0, 30 unit operating days [c,e]
	Gas	CTG & DB	2.0	22.8	2.0, 30 unit operating days [c,e]
		CTG Normal Mode	2.0	19.3	
VOC [f]	Oil	CTG	6.0	18.9	NA
	Gas	CTG & DB	1.9	7.2	
		CTG Normal Mode	1.5	4.8	
NH_3 [g]	Oil/Gas	CTG, All Modes	5	NA	NA
SAM/SO_2 [h]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil VE shall not exceed 10% opacity for each 6-minute block average.		
PM/PM_{10} [i]					

a. Concentration standards are given in terms of parts per million, by volume, dry at 15 percent oxygen and abbreviated as ppmvd.

b. The mass emission rate standards in pounds per hour (lb/hr) are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations filed with the Department.

c. "Unit operating day" means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period. [40 CFR 60.4420]

d. Compliance with the continuous 30-unit operating days rolling CO standard shall be demonstrated based on data collected by the required CEMS. The initial EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate initial performance guarantees for natural gas, oil, and basic DB mode.
e. Continuous compliance with the 30-unit operating days rolling NO_X standards shall be demonstrated based on data collected by the required CEMS and will also insure compliance with the less stringent Subpart KKKK limits of 15 and 42 ppmvd for gas and fuel oil respectively on a 30-unit operating day rolling average basis. The initial EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as nitrogen dioxide (NO_2).
f. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.
g. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.
h. The clean fuel sulfur specifications and VE standard effectively limit the potential emissions of SAM and SO_2 from the CTG. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.
i. The clean fuel sulfur specifications, low CO and NO_X limits, and the VE standard will effectively limit $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the VE standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

4.6 National Emission Standards for Hazardous Air Pollutants Applicable to CTG

FPL estimates future HAP emissions from the CCEC at less than 20 TPY total and less than 10 TPY of a single HAP (formaldehyde). The Department accepts the estimates for this project. Based on the fuels fired and the kind of equipment installed, there is no reason to expect higher levels of HAP emissions. As such, the proposed new CTG would not be subject to 40 CFR 63, Subpart YYYY which became final on March 5, 2004.

4.7 Emission Standards for Boilers

Two small boilers are required for this project. The first is an auxiliary boiler rated at 99.8 mmBtu/hr that will be used less than 500 hours per year (hr/yr). The purpose of the auxiliary boiler is to provide steam for combustor cooling until steam of sufficient quality can be provided by the HRSG.

The second is temporary boiler rated at 110 mmBtu/hr that will be removed by expiration date of the permit. It will also be used less than 500 hr/yr. The purpose of the temporary boiler is to provide steam to clean (such as by steam blows) construction activity residues from surfaces in the CTG, HRSG and STG construction.

The auxiliary boiler and temporary boiler are subject to 40 CFR 60, Subparts Dc and Db respectively. FPL has proposed and the Department accepts the following emission standards for the boilers. The requirements from Subparts Db and Dc are shown for comparison purposes.

Table 7. Applicant Proposal for SO_2, CO, NO_X, VOC, PM Standards – Boilers

Source	SO_2 (gas S spec.)	CO (lb/mmBtu)	PM/PM_{10} (lb/mmBtu)	VOC (lb/mmBtu)	NO_X (lb/mmBtu)
Temp. Boiler	2 gr S/100 SCF	0.08	0.007	0.005	0.050
Aux. Boiler					
Subpart Db	Not applicable (NA) for natural gas firing				0.20
Subpart Dc	Sources between 10 and 100 mmBtu/hr - record keeping required				

It is noted that the requirements of the applicable NSPS are minimal. Because of the large reductions in the emissions of all pollutants (except for CO) due to the project, limits for VOC, NO_X and PM/PM_{10} are not necessary for the auxiliary boiler. However the requested CO and NO_X limits will be reflected in the permit with reliance on the fuel specification and a VE standard for the rest.

4.8 Emissions Standard for Natural Gas Process Heaters

Two natural gas heaters rated at 10 mmBtu/hr are required for the project. One is designated as a spare. The purpose of these units is to heat natural gas above dew point temperature and prevent condensation. The gas heaters are subject to 40 CFR 60, Subpart Dc.

FPL has proposed and the Department accepts the following emission standards for the two natural gas heaters. The minimal requirement from Subpart Dc is shown for comparison purposes.

Table 8. Emission Standards for Emissions from Natural Gas-fired Fuel Process Heaters

Source	SO_2 (gas S spec.)	NO_X (lb/mmBtu)	CO (lb/mmBtu)	VOC (lb/mmBtu)	PM (lb/mmBtu)
Application	2 gr S/100 SCF	0.095	0.08	0.005	0.002
Subpart Dc	Sources between 10 and 100 mmBtu/hr - record keeping required				

The requested CO and NO_X limits will be reflected in the permit with reliance on the fuel specification and a VE standard for VOC, SO_2 and PM.

4.9 Emissions Standard for the Compressor Station

Seven natural gas compressors rated at 1,340 horsepower (hp) are required for the project. The compressors will have four-stroke, lean burn, spark ignition engines. These will be used to increase pressure from the existing Florida Gas Transmission (FGT) lateral pipeline to Unit 3. The gas compressors are subject to the requirements for non-emergency lean burn engines at 40 CFR 60, Subpart JJJJ.

FPL has proposed and the Department accepts (with exception of the NO_X proposal) the following emission standards for the seven compressors. The requirements for such engines from Subpart JJJJ are shown for comparison purposes.

Table 9. Emission Standards for Compressors - grams per horsepower-hour (g/hp-hr)

Source (manufacture date)	CO (g/hp-hr)	VOC (g/hp-hr)	NO_X (g/hp-hr)	PM (lb/mmBtu)	SO_2 (gas S spec.)	VE (opacity)
Compressors (application)	0.10	0.16	1.5	0.0099[a]	2 gr/100scf	10%
Subpart JJJJ (1/1/2008)	4.0	1.0	2.0	NA		
Subpart JJJJ (after 7/1/2010)	2.0	0.7	1.0			

a. 0.0099 lb/mmBtu equals approximately 0.034 g/hp-hr. Units in the permit will be expressed as g/hp-hr.

The specification given in the application would also meet the Subpart JJJJ NO_X requirement of a model year 2008 engine but not the NO_X requirement of an engine manufactured on or after July 1, 2010. Based on discussions between the Department and intended manufacturer, engines to meet the more stringent 7/1/2010 will be available. According to the application, the compressor engines will be equipped with oxidation catalysts and will thus be low CO and VOC emitters.

The requested VOC, CO and NO_X limits will be reflected in the permit with reliance on the fuel specification and a VE standard for the SO_2 and PM limit.

These compressors are Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the compressors must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart JJJJ.

4.10 Emissions Standard for Diesel Emergency Generators

Two standby diesel emergency generators rated at 2,250 kW (3,200 brake hp) are required for the project. These will be used when electricity is not available to the site, such as during hurricanes. The emergency generators are subject to 40 CFR 60, Subpart IIII.

FPL has proposed and the Department accepts the following emission standards for the two emergency generators. The identical requirements (except for fuel specification) from Subpart IIII for emergency generators constructed in 2007-2010 are shown for comparison purposes.

Table 10. Emission Standards for Diesel Emergency Generators.

Source (model year)	CO (g/hp-hr)	Hydrocarbons (HC) (g/hp-hr)	NO_X (g/hp-hr)	PM (g/hp-hr)	SO_2 (oil S spec.)	VE
Application	8.5	1.0	6.9	0.4	0.0015	10%
Subpart IIII (2007-2010)	8.5	1.0	6.9	0.4	NA	
Subpart IIII (2011 and later)	2.6	4.8 Non-methane HC+ NO_X		0.15		

The permit will reflect the requirement to adhere to the appropriate Subpart IIII values and will include the requested ULSD fuel oil specification and VE limit. If the applicant selects a later model year (2011 or later), it will be necessary to adhere to more stringent limitations than proposed in the application.

These diesel emergency generators are Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the compressors must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.

4.11 Emissions Standards for Emergency Fire Pump Engines

One 300-horsepower (hp) fire pump engine is required for the project. It will be used sparingly and will fire ULSD fuel oil. The gas compressors are subject to 40 CFR 60, Subpart IIII.

FPL has proposed and the Department accepts the following emission standards for the fire pump engine. The requirements for such engines constructed in 2008 and in 2009 (and thereafter) from Subpart IIII are shown for comparison.

Table 11. Emission Standards for Emergency Fire Pump Engines.

Source (model year)	CO (g/hp-hr)	VOC (g/hp-hr)	NO_X (g/hp-hr)	PM (g/hp-hr)	SO_2 (oil S spec.)
Application	2.6	1.0	6.8	0.40	0.0015
Subpart IIII (2008)	2.6	7.8 (NMHC[a]+NO_X)		0.40	NA
Subpart IIII (2009+)[b]	NA	3.0 (NMHC+NO_X)		0.15	

a. NMHC is the acronym for non-methane hydrocarbons. NMHC are approximately equal to VOC for these sources.

b. Model year 2009-2011engines with speed greater than 2,650 revolutions per minute (rpm) comply with model 2008 requirements. Fire pumps such as planned for the project typically exhibit much less than 2,650 rpm.

The permit will reflect the requirement to adhere to the appropriate Subpart IIII values (e.g. NMHC instead of VOC) and will include the requested ULSD fuel oil specification. If the applicant selects a model year of 2009 (or later), it will be necessary to adhere to more stringent limitations.

5. PERIODS OF EXCESS EMISSIONS

5.1 Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

5.2 Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed standards based on the given characteristics of the specific project.

During a cold startup of the STG system, each CTG/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue. The gradual warming of the HRSG and STG components is accomplished by operating the CTG for extended periods at reduced loads, which results in higher emissions. The durations are minimized by use of the auxiliary steam generators proposed for the project. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from FPL regarding startup and shutdown, the Department establishes the following conditions for excess emissions for the CTG/HRSG system.

Excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each CTG/HRSG system, excess emissions NO_X resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

a. *STG/HRSG System Cold Startup*: For cold startup of the steam turbine system, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed eight (8) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

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

b. *Shutdown Steam Turbine System*: For shutdown of steam turbine system, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed three (3) hours in any 24-hour period.

c. *CTG/HRSG System Cold Startup*: For cold startup of a CTG/HRSG system, excess NO_X and CO emissions shall not exceed four (4) hours in any 24-hour period. "Cold startup of a CTG/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

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

e. *Startup and Shutdown Opacity*: During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

For startup, NH_3 injection shall begin as soon as the system reaches the manufacturer's specifications. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG.

While NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation.

5.3 Initial Compliance Determinations if Siemen's H CTG is utilized

The proposed model turbine would be the first Siemens H turbine designed and manufactured for 60Hz operation. During commissioning of the Siemens H CTG for the Project, the first CT in the 3-on-1 configuration will undergo comprehensive commissioning and validation tests using a separate exhaust stack. This commissioning will require an extension of the requirements for initial testing of the first gas turbine to allow for an initial test period of up to three months. This first gas turbine will then be shut down for a month, undergo an inspection outage, and then may receive some new combustion components to be prepared for combined cycle operation. The entire 3-on-1 block will then go into normal startup activities that will be on the order of up to 180 days. Therefore, the maximum testing period required is three months, which would be in addition to normal start-up activities. Following testing, a short outage would occur for inspection and removal of the temporary stack, installation of the HRSG transition duct, then resumption of normal commissioning tests.

6. AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

The proposed CCEC project will not increase emissions of criteria pollutants at levels in excess of PSD significant emission rates (SER).

Although the proposed project is not PSD applicable, the applicant provided an air quality analysis to ensure that the conversion will not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS).

6.2 Major Stationary Sources in Brevard County

The current largest stationary sources in Brevard County are listed below. The information is from annual operating reports submitted to the Department from 2007. The future estimates for the FPL CCEC that will replace the CCP are included for comparison.

Table 12. Major Sources of SO_2 in Brevard County

Owner	Site Name	Tons per year (TPY)
Florida Power & Light	CCP (will be shut down)	4,057
Reliant Energy Florida	Indian River Power Plant	914
Florida Power & Light	**CCEC (future estimate)**	**210**
Brevard Energy	Brevard Energy (Proposed)	69
Board of Co. Commissioners	Co. Central Disposal Facility	36
Intersil Corporation	Intersil –Palm Bay	24

Table 13. Major Sources of NO_X in Brevard County

Owner	Site Name	Tons per year
Florida Power & Light	CCP (will be shut down)	3,499
Florida Power & Light	**CCEC (future estimate)**	**506**
Reliant Energy Florida	Indian River Power Plant	335
Oleander Power Project, LP	Oleander Power Project	178
NASA	NASA/Kennedy Space Center	42
U.S. Air Force	Patrick Air Force Base	20

Table 14. Largest Sources of PM_{10} in Brevard County

Owner	Site Name	Tons per year
Florida Power & Light	CCP (will be shut down)	378
Florida Power & Light	**CCEC (future estimate)**	**189**
Reliant Energy Florida	Indian River Power Plant	45
Oleander Power Project, LP	Oleander Power Project	21
Morton International	Morton Salt/Port Canaveral	8

Table 15. Largest Sources of CO in Brevard County

Owner	Site Name	Tons per year
Florida Power & Light	CCP (will be shut down)	694
Florida Power & Light	**CCEC (future estimate)**	**533**
Board of Co. Commissioners	Co. Central Disposal Facility	59
NASA	NASA/Kennedy Space Center	47
Reliant Energy Florida	Indian River Power Plant	39
Oleander Power Project, LP	Oleander Power Project	22

Table 16. Largest Sources of VOC in Brevard County

Owner	Site Name	Tons per year
Sea Ray Boats Inc.	Sea Ray Boats	254
Florida Power & Light	**CCEC (future estimate)**	**105**
Florida Power & Light	CCP (will be shut down)	58
Transmontaigne, Inc.	Cape Canaveral Terminal	50
Intersil Corporation	Intersil –Palm Bay	23
U.S. Air Force	Patrick Air Force Base	23

6.3 SO_2 and NO_X Trends from FPL Peninsular facilities

To put the emissions from the existing CCP and the future CCEC into the larger perspective, the Department graphed the SO_2 and NO_X emission trends during the period 1998-2007 from FPL fossil-fueled plants located in the Florida peninsula. The data source is the EPA Clean Markets Acid Rain database. The results are summarized in Figure 10.

During the period 1998-2007 there was a *decrease* from 221,400 to 50,900 TPY (77%) in SO_2 emissions from the FP&L fossil fleet in peninsular Florida. Similarly there was a *decrease* from 98,500 to 31,800 TPY (68%) in NO_X emissions. Some of these reductions occurred at the CCP.

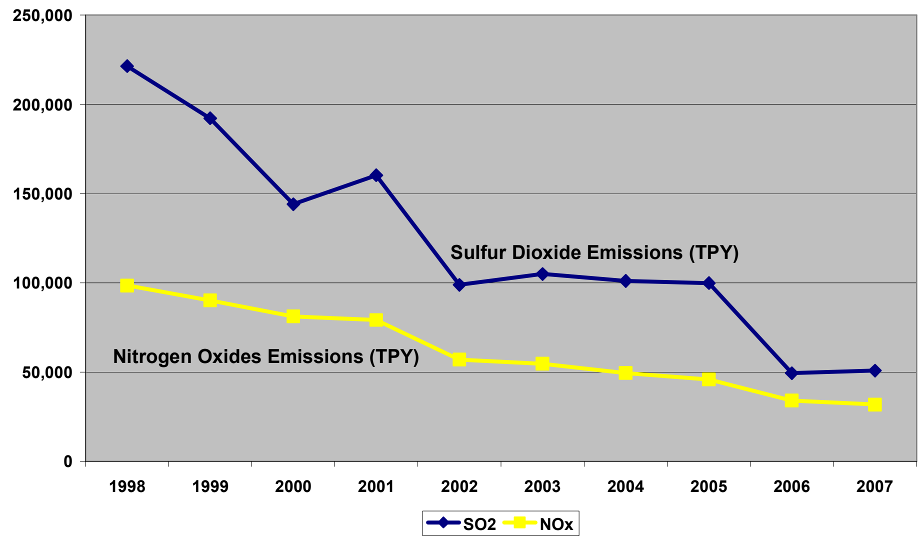


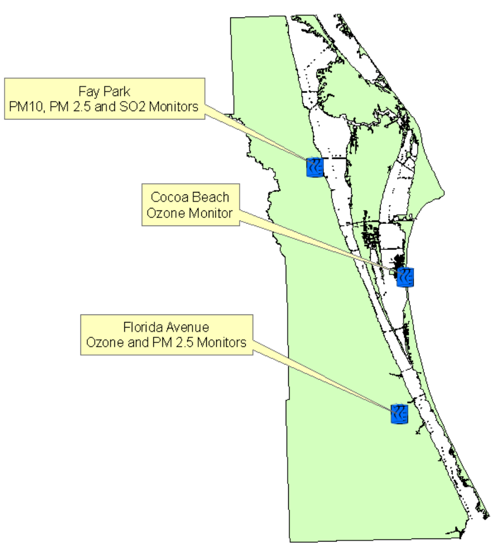
Figure 10 – SO_2 and NO_X reductions at FPL peninsular facilities (1998-2007)

There will be approximately 4,000 TPY of further reductions in SO_2 and approximately 3,500 TPY of further reduction in NO_X due to the shut down and dismantlement of the CCP and replacement with the CCEC. For comparison purposes, the future CCEC will emit a little more than 200 TPY of SO_2 and 500 TPY of NO_X.

6.4 Air Quality and Monitoring in the Brevard County

The Department's Central District operates six criteria pollutant monitors at three sites measuring PM_{10}, $PM_{2.5}$, ozone (O_3) and SO_2. The 2007 monitoring network is shown in Figure 11 below.

On March 12, 2008 the U.S. Environmental Protection Agency announced that it will reduce the 8-hour ozone standard listed above from 85 parts per billion (ppb) to 75 ppb. Upon final redesignation and classification, most likely in 2010, the areas shown in red in Figure 12 will likely no longer be in attainment with the applicable ozone AAQS.



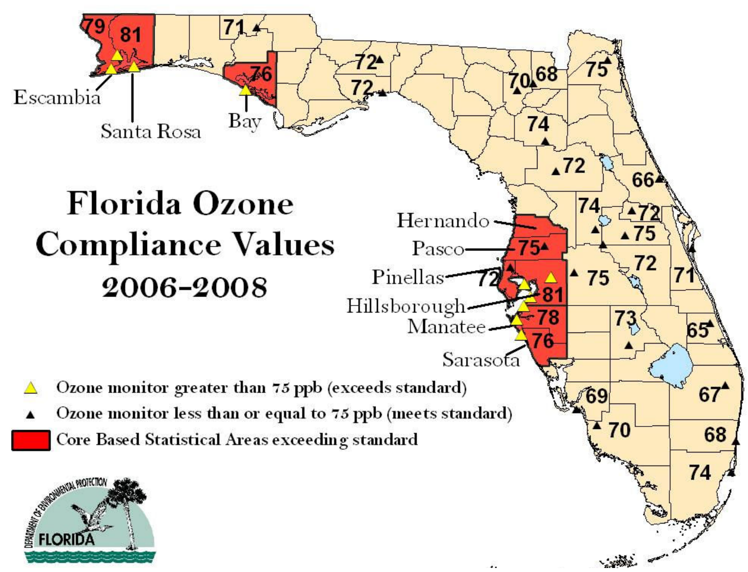


Figure 11. Ambient Monitors in Brevard County. Figure 12. Ozone Compliance Values

The 2007 (quality-assured) ambient air quality summaries for the stations nearest to the project site are presented in Table 17. Based on the data including the preliminary 2008 measurements, Brevard County will remain in attainment with the new ozone standard.

Table 17. Ambient Air Quality Nearest to Project Site (2007)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Fay Park	24-hour	74	34		150[a]	ug/m^3
		Annual			16	50[b]	ug/m^3
$PM_{2.5}$	Florida Avenue Melbourne	24-hour	23	22		35[c]	ug/m^3
		Annual			7	15[d]	ug/m^3
SO_2	Fay Park	3-hour	29	24		500[e]	ppb
		24-hour	6	5		100[e]	ppb
		Annual			1	20[b]	ppb
NO_2	Orlando	Annual			7	53[b]	ppb
CO	Orlando	1-hour	4	4		35[e]	ppm
		8-hour	2	2		9[e]	ppm
Ozone	Cocoa Beach	1-hour	86	80		120[a]	ppb
		8-hour	81	73		75[f,g]	ppb
		8-hour	2007 3-yr attainment		72[f]	75[g]	ppb
		8-hour	2008 3-yr average		71[f]	75[g]	ppb

a. Not to be exceeded on more than an average of one day per year over a three-year period
b. Arithmetic mean
c. Three year average of the 98th percentile of 24-hour concentrations
d. Three year average of the weighted annual mean
e. Not to be exceeded more than once per year
f. Three year average of the 4th highest daily max
g. New EPA standard for ozone

6.5 Air Quality Impact Analysis

The applicant provided an air quality analysis which included air quality modeling to show compliance with the NAAQS.

Receptor Grid: A combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at the property line and extending to 2 kilometers. Beyond 2 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 5 kilometers from the facility.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project. AERMOD was approved by the EPA in November 2005. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service at Daytona Beach (KDAB) and Jacksonville International Airport respectively. The 5-year period of meteorological data was from 2001 through 2005. The surface weather station was selected for use in this study because the modeling results were more conservative with regards to comparing surface parameters at KDAB and the project site. The Jacksonville station was selected for use in the study because it is the most representative with regards to this region.

AAQS Analysis

The total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown in this table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

Table 18. Ambient Air Quality Impacts Post-Conversion

Pollutant	Averaging Time	Major Sources Impact (μg/m^3)	Background Conc. 2005- 2008 (μg/m^3)	Total Impact (μg/m^3)	Total Impact Greater Than AAQS?	Florida AAQS (μg/m^3)
PM_{10}	24-hour	5	48	53	NO	150
	Annual	0.5	15.6	16.1	NO	50
SO_2	24-hour	3	13	16	NO	260
	Annual	1	3	4	NO	60
	3-hour	12	63	75	NO	1,300
NO_2	Annual	9	16	25	NO	100
CO	1-hour	124	8,925	9,049	NO	40,000
	8-hour	70	2,975	3,045	NO	10,000

6.6 Additional Impacts Analysis

Ozone

Ozone is an area-wide pollution issue and the solution to reducing ozone levels is broad-based local and regional reductions in NO_X and VOC emissions (the precursors to ozone formation).

The continuing FPL system-wide NO_X decreases in general (Figure 10), including those due to the CCEC project in particular should help to reduce ozone on a regional basis including Brevard County (given cooperation of meteorological factors). The ozone benefits of such reductions will be reinforced by reductions due to implementation of other NO_X control projects, particularly at coal-fueled power plants around the state as many install controls under the Clean Air Interstate Rule (CAIR).

Impact on Soils, Vegetation, and Wildlife:

Substantial net emissions reductions of approximately 20,000 TPY (5 year average, 2003 through 2007) of pollutants from the Cape Canaveral project for sulfuric acid mist, SO_2, PM_{10} and NO_X will help ameliorate past air pollution effects on soils, vegetation and wildlife. The applicant modeled the impacts from the existing facility for comparison purposes.

Impact on Visibility:

There will be significant visibility improvements in the immediate vicinity because of the reduction of particulate emissions due to the CCEC project and the very significant reductions in condensable and fine particulate precursors. The existing units are subject to opacity limitations of 40 percent under present normal operation whereas the replacement units will be subject to a 10% opacity standard.

7. Preliminary Determination

The Department makes a preliminary determination that the proposed CCEC Project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, the draft emissions standards determinations, review of the air quality impact analysis, and the conditions specified in the draft permit.

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