TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Polk Power Station Unit 1
Facility ID No. 1050233

PROJECT

Project Nos. 1050233-029-AC (PSD-FL-194J)
Re-Permitting IGCC Unit 1

1050233-032-AC (PSD-FL-263B and PSD-FL-363C)
Minor Permit Modifications for Units 2, 3, 4 and 5

COUNTY

Polk County, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

September 27, 2012

1. GENERAL PROJECT INFORMATION

1.1 Air Pollution Regulations

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following applicable chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring), F.A.C. Specifically, air construction permits are required pursuant to Rules 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial categories. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations on a quarterly basis in Rule 62-204.800, F.A.C.

1.2 Facility Description and Location

The Tampa Electric Company (TECO) operates the existing Polk Power Station, which is an electric power plant consisting of five key electrical generating units (Units 1 to 5). The facility is categorized under Standard Industrial Classification Code No. 4911, for electrical services. The existing plant is located in Polk County at 9995 State Road 37 South in Mulberry, Florida. The UTM coordinates are Zone 17, 402.45 kilometers (km) East, and 3,067.35 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to state and federal Ambient Air Quality Standards (AAQS). Figure 1 shows the location of Polk County while Figure 2 shows an aerial view of Unit 1 at the PPS. The current Title V Air Operation Permit under which the PPS operated is No. 1050233-026-AV.

Figure 1 – Polk County in Florida

Figure 2 - TECO PPS Unit 1 IGCC Plant

Unit 1 consists of a nominal 260 megawatt (MW) solid fuel-based integrated gasification and combined cycle (IGCC) plant including: a nominal 192 MW (gross) syngas and No. 2 fuel oil-fired General Electric (GE) 7FA combustion turbine-electrical generator (CCCT) designated as Emission Unit (EU) 001; a heat recovery steam generator (HRSG); a nominal 123 MW (gross) steam turbine-electrical generator (STEG); a solid fuel handling system designated as EU 005; an entrained flow solid fuel gasification system designated as EU 006; an oxygen plant; a synthetic gas (syngas) cleanup and sulfur recovery system; and a sulfuric acid plant (SAP) designated as EU 004. There is also a 120 million British thermal units per hour (MMBtu/hr) auxiliary boiler designated as EU-003. Approximately 65 MW are consumed by the oxygen plant and process auxiliary equipment which is the difference between net and gross power production. Currently the startup fuel for the SAP and solid fuel gasifier is propane. No. 2 fuel oil is used as the augmentation and backup fuel for the CCCT, while it is the only operational fuel used in the auxiliary boiler. The maximum sulfur content of the No. 2 fuel oil used in all the units is 0.05% by weight.

Units 2 and 3 (EU 009 and 010) at the facility are two 165 MW natural gas/fuel oil-fired GE 7FA simple cycle CTG, while Units 4 and 5 (EU 011 and 012) are two 165 MW natural gas-fired GE 7FA simple cycle CTG.

1.3 Facility Regulatory Categories

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The facility operates units subject to the New Source Performance Standards in Part 60, Title 40 of the Code of Federal Regulations.

1.4 Project Description

On February 28, 2012, the Department received an application from TECO to modify several permit conditions in current Title V air operation Permit No. 1050233026-AV related to:

1) The fuel sulfur monitoring requirement and sulfur dioxide (SO_2) emission limit for the auxiliary boiler (EU 003);
2) The limits by weight pertaining to the blend of petroleum coke and coal used in the entrained flow solid fuel gasification system (EU 006);
3) The nitrogen oxide (NO_X) emissions reporting when firing natural gas and fuel oil in two of the 160 MW simple cycle CTG (EU 009 and 010);
4) The fuel monitoring schedule for these same CTG; and

These revisions require changing several permit conditions in previously issued PSD permits and the applicant submitted a request for a concurrent air construction permit revision to make these changes to the PSD permits on March 8, 2012. On May 9, 2012 a draft/proposed permit package for this project was issued by the Department. Subsequently, TECO has requested four extension of time to petition for a formal administrative hearing for this permit package. The latest extension runs through September 7, 2012.

On May 21, 2012, the Department received from TECO an application for concurrent air construction permit and Title V air operation permit revisions regarding startup, augmentation, and backup fuels used in Unit 1 (the IGCC Plant). Specifically, it was requested that pipeline natural gas replace the propane

currently used as the startup fuel for the solid fuel gasification system preheater burners and the SAP burners. Additionally, it was requested that natural gas replace the No. 2 fuel oil used as the backup fuel for the CCCT while also allowing natural gas to be used to augmentation syngas firing as required in the CCCT. Finally, it was requested that natural gas replace No.2 fuel oil as the only allowable fuel used in the auxiliary boiler. The major components of the oil-to-natural gas conversion project are:

1) Combustion of natural gas instead of No. 2 fuel oil in the auxiliary boiler;
2) Combustion of natural gas instead of propane in the SAP hydrogen sulfide (H_2S) to sulfur dioxide (SO_2) conversion furnace burners and the SAP SO_2 to sulfur trioxide (SO_3) converter preheater burners;
3) Combustion of natural gas instead of propane in the solid fuel gasifier preheater;
4) Use of natural gas instead of No. 2 fuel oil as a back-up fuel for the CCCT; and
5) That natural gas can be allowed to be used to augmentation syngas firing in the CCCT.

The applicant provided the following description of the syngas/natural gas burner system that will be used in the CCCT of Unit 1. In addition, the applicant explained the reason why a DLN (Dry Low-NO_X) control system cannot be used to control NO_X emissions from the CCCT.

"The two systems (syngas and natural gas) will share a burner assembly. Our syngas multi – nozzle quiet combustion (MNQC) nozzles will be used for both syngas and natural gas. DLN nozzles cannot be combined with MNQC nozzles so both the syngas and natural gas will need to run through these type of nozzles.

In the MNQC used for syngas, the combustion zone downstream of the fuel nozzles is relatively open, i.e., when the fuel leaves its nozzle, it burns in a relatively open area. In DLN combustors, the combustion zone is more complicated. It includes a relatively large premix zone where some of the gas and air are combined prior to combustion (staged combustion). Manufacturers have not been able to develop DLN combustion systems to accommodate syngas because the high flame speed of hydrogen (a major constituent of the syngas) causes the flame to backfire into the premix zone. Another practical reason why syngas and natural gas cannot be combined in a DLN system in a 7F turbine is that fuel piping to a DLN combustion can be much more complicated than to a MNQC system and syngas piping is much larger than natural gas piping. This means that there is not enough room for both syngas and natural gas piping onto and around the end cover."

The applicant provided the following description of the type of NO_X control that will be used in the CCCT:

"When syngas is running, NO_X is controlled by nitrogen injection, supplemented by some water vapor introduced into the syngas saturator. This is the case if syngas is running alone or with some natural gas augmentation. When natural gas is running, NO_X is controlled with steam injection alone."

In addition, the applicant has requested that the heat input rate for the CCCT which is currently set at a maximum of 1,755 MMBtu/hr when firing syngas and 1,765 MMBtu/hr when firing No. 2 fuel oil at an ambient temperature of 59 degrees Fahrenheit (ºF) be changed to a nominal heat input rating basis. The nominal rate would be 1,642 MMBtu/hr at 59 ºF when firing syngas, natural gas or syngas augmented by natural gas. The applicant also requested that stack testing for compliance purposes be limited to within 10 % of the nominal heat input rate and that manufacturer's curves approved by the Department may be utilized to establish the nominal maximum heat input rates for compliance determination purposes.

On July 18, 2012, TECO requested that the above described projects be combined into a single project. TECO made this request because the two projects are interrelated. Once the conversion of Unit 1 to natural gas is completed, the fuel oil sulfur monitoring requirement and sulfur dioxide emission limit permit changes relating to the auxiliary boiler (EU 003) requested in the February 28, 2012 permit application will become obsolete and superseded by requirements related to natural gas firing in the boiler. Thus to avoid confusion, by having two active, interrelate , and in the case of the auxiliary boiler, conflicting air construction and Title V permit revisions, the projects were merged.

Also, as part of comments received from the applicant on the initial draft permit package, a request was made to modify the Dry Low-Nitrogen Oxides (DLN) tuning requirement for the simple cycle gas-fired turbine Units 4 and 5. Finally, the applicant also requested that the emission unit numbers of Units 4 and 5 be changed from EU 011 and EU 012 to EU 013 and EU 014 to match what is in the Departments Air Resource Management System (ARMS) database.

To accomplish the changes relating to Unit 1 at the PPS, the Department decided to re-permit Unit 1 by incorporating the original PSD construction permit (PSD-FL-194) and all subsequent construction permit modifications into a "clean" new construction permit that also includes the permit changes requested by TECO. In addition, redundant and obsolete permit conditions and emission limits were removed from the new "clean" permit (PSD-FL-194J, Project No. 1050233-029-AC).

The other permit changes requested by TECO relating to Units 2 through 5 were accomplished by modifying the construction permits PSD-FL-263 for Units 1 and 2 and PSD-FL-363 for Units 4 and 5. These changes are reflected in the new permits PSD-FL-263B and PSD-FL-363C. Both of these new permits were assigned Project No. 1050233-032-AC. All of these changes in the PSD permits (194J, 263B and 363C) and are reflected in the Title V revision (DEP File No. 1050233-028-AV) that is being issued concurrently with the three underlying PSD construction permit revisions. These changes and other minor changes that were made are described in this document and the Statement of Basis (SOB) document relating to the Title V permit revision that is included in the permit package.

In summary, permit changes affecting Unit 1 at the PPS are addressed in Project No. 1050233-029-AC (PSD-FL-194J). Changes pertaining to Units 2 to 5 at the PPS are addressed in Project No. 1050233-032-AC (PSD-FL-263B and PSD-FL-363C). All these permit changes for Units 1 to 5 at the PPS will also be reflected in the revised Title V Air Operation Permit (No. 1050233-028-AV). All these permits and associated document are included in the issued draft/proposed permit package.

1.5 Processing Schedule

02/28/2012: Received an application for a Title V air permit revision to change the auxiliary boiler fuel sulfur monitoring requirement and sulfur dioxide emission limit and the visible emission monitoring requirement for the sulfuric acid plant along with other changes **Project 1**.

03/08/2012: Received an application for concurrent air construction permit revision for **Project 1**.

04/23/2012: Issued Air Construction Permit and draft/proposed Title V Air Permit revisions for **Project 1**.

05/17/2012: Tampa Electric Company requested an extension of time to petition for a formal administrative hearing until the close of business on July 6, 2012 for **Project 1**.

05/21/2012: Received an application for concurrent air construction permit and Title V air permit revision to convert the backup and startup fuels of Unit 1 from fuel oil and propane to natural gas (**Project 2**).

06/26/2012: Tampa Electric Company requested a second extension of time to petition for a formal administrative hearing until the close of business on August 6, 2012 for **Project 1**.

07/18/2012: Received a request from TECO to combine the two projects.

08/06/2012: Tampa Electric Company requested a third extension of time to petition for a formal administrative hearing until the close of business on August 6, 2012 for the **combined projects**.

08/20/2012: Tampa Electric Company requested a forth extension of time to petition for a formal administrative hearing until the close of business on September 18, 2012 for **the combined projects**.

2. PSD APPLICABILITY

2.1 General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal AAQS or areas designated as "unclassifiable" for these regulated pollutants. PSD pollutants include: carbon monoxide (CO); NO_X; sulfur dioxide (SO_2); particulate matter (PM); PM smaller than 10 micrometers (PM_{10}); volatile organic compounds (VOC); lead (Pb); Fluorides (F); sulfuric acid mist (SAM); total reduced sulfur (TRS), including hydrogen sulfide (H_2S); municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (D/F); MWC metals measured as PM; MWC acid gases measured as SO_2 and hydrogen chloride (HCl); and mercury (Hg).

As defined in Rule 62-210.200(179)(a)1, F.A.C., a "major stationary source" is any of 28 listed stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year (TPY) or more of any PSD pollutant. Link to Rule 62-210, F.A.C. The list given in the citation includes the category of "fossil fuel-fired steam electric plants of more than 250 MMBtu/hr". The Polk Power Station is a major stationary source based on its actual emissions and its potential to emit PSD pollutants. The major stationary source threshold for source categories not on the cited list is 250 TPY or more of any PSD pollutant.

For major stationary sources, PSD applicability is based on emissions thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200, (Definitions) F.A.C. Emissions of PSD pollutants from the project that equal or exceed these SER are considered "significant". Best Available Control Technology (BACT) must be employed to minimize emissions of each PSD pollutant and an air quality impact analysis must be conducted for the PSD pollutants for which AAQS are defined. SER also means any emissions rate or any net emissions increase of a PSD pollutant associated with a major stationary source or major modification which would construct within 10 km of a Class I area and have an impact on such area equal to or greater than 1 gram per cubic meter, 24-hour average.

Although a facility may be "major" for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding SER given in Table 1.

Table 1 – List of SER by PSD-Pollutant [1, 3]

Pollutant	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO_X	40
$PM/PM_{10}/PM_{2.5}$	25/15/10	Ozone (VOC) [2]	40
Ozone (NO_X) [2]	40	SAM	7
SO_2	40	F	3
Pb	0.6	TRS	10
H_2S	10	Hg	0.1

1. Excluding those defined exclusively for MWC and MSW landfills.
2. Ozone (O_3) is regulated by its precursors (VOC and NO_X).
3. There is a federal SER of 75,000 TPY for Greenhouse Gases (GHG) as CO_2 equivalent (CO_2e) that has not been incorporated into Department rules. .

2.2 PSD Applicability for the Projects

Both projects will be located in Polk County, which is in an area that is currently in attainment with (or designated as unclassifiable for the state and federal AAQS

2.2.1 Project 1

According to the applicant, no emission increases will result from the proposed project. Therefore, the project is not subject to PSD preconstruction review.

2.2.2 Project 2

The applicant submitted a PSD applicability analysis which is presented in Table 2 below.

Table 1 – Applicant's PSD Analysis, Emissions in TPY.

Parameter	Baseline Emissions	Total Future Actual Emissions	Net Change	PSD Threshold
SO_2	1,160.3	1,150.0	-10.3	40
NO_X	391.7	422.6	**30.9**	40
PM Total	35.2	39	3.8	25
PM (f) [1]	0.1	1.5	1.4	15
PM (c) [1]	35.1	37.1	2.0	15
VOC	4.7	4.6	-0.1	40
CO	79.0	79.4	0.4	100
CH_4 [1]	150.0	150.0	0.0	NA[2]
N_2O [1]	22.1	22.0	-0.1	NA[2]
CO_2	1,764,380	1,752,040	-12,340	NA[2]
CO_2e	1,777,420	1,762,040	-15,380	75,000 [2]

1. f = filterable portion of PM; c = condensable portion of PM; CH_4 = Methane; and NO_2 = Nitrous oxide.
2. There is a federal SER of 75,000 TPY for Greenhouse CO_2e that has not been incorporated into Department rules.

Based on the applicant's PSD analysis, no emission increases resulting from the project will exceed the SER for any pollutant and the project does not trigger PSD preconstruction review.

2.2.3 Other Minor Changes

TECO made a request to modify the DLN tuning requirements for the simple cycle gas-fired turbine Units 4 and 5. Specifically, TECO requested a requirement to report excess NO_X emissions on a quarterly basis and removal of the requirement for an advance notice of tuning. These changes do not effect emissions from the units and will provide the applicant with more flexibility with regard to tuning activities. TECO also requested that the emission unit numbers of Units 4 and 5 be changed from EU 011 and EU 012 to EU 013 and EU 014 to match that ID Nos. established the Department's ARMS database. These changes are very minor in scope and will not be discussed further in the following Project Review Section.

3. PROJECT REVIEW

3.1 State Regulations, Projects 1 and 2

The facility will continue to operate under its existing air construction and facility Title V operation permits. The most recent applicable permit is Title V Permit No. 1050233-026-AV available at:

Link to current Title V Permit

3.2 Federal Regulations Relating to Project 2

3.2.1 NSPS Applicability

There are no NSPS that apply to the burners used in the sulfuric acid plant H_2S to SO_2 conversion furnace, the sulfuric acid plant SO_2 to SO_3 converter preheater, and the solid fuel gasifier preheater. There are potentially NSPS that are applicable to the CCCT and auxiliary boiler of Unit 1 after the oil-to-natural gas conversion project. These NSPS are discussed below.

3.2.1.1 *NSPS Subpart Da - Electric Utility Steam Generating Units*

NSPS Subpart Da applies to electric utility steam generating units that commence construction, modification or reconstruction after September 18, 1978, and that are capable of combusting more than 250 MMBtu/hr heat input of fossil fuel. IGCC electric utility steam generating unit (associated duct burners) are subject to Subpart Da and are not subject to NSPS Subparts GG or KKKK if both of the following conditions are met: the IGCC electric utility steam generating unit is capable of combusting more than 250 MMBtu/hr of heat input from fossil fuels (either alone or in combination with any other fuel); and the IGCC electric utility steam generating unit commenced construction, modification, or reconstruction after February 28, 2005. Unit 1 is capable of combusting more than 250 MMBtu/hr of heat input from fossil fuels, but the planned changes to Unit 1 are not considered modifications pursuant to NSPS Subpart A. Specifically, per NSPS Subpart A §60.14(e)(h) a change is not a considered a modification if:

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the ***maximum hourly emissions*** *of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.*

Table 3 provides the applicant's comparison of maximum hourly emission rates for PM, NO_X, SO_2, and Hg following the planned changes to Unit 1 to the maximum hourly rates that occurred during the past 5 years. These are the pollutants that have NSPS Subpart Da emission standards. As shown, no hourly increases in pollutant emissions are expected to occur as a result of this project. Thus, according to the applicant, the natural gas conversion is not considered a modification with regard to NSPS applicability.

Table 2 – Applicant's Comparison of Unit 1 Maximum Hourly Emission Rates

Parameter	Past Actual Maximum Hourly Average (lbs/hr)	Future Actual Maximum Hourly Average (lbs/hr)
SO_2	848.8	309.3
NO_X	423.3	112.7
PM total	13.3	10.8
Hg	0.003	0.002

The Department agrees that the conversion to natural gas should not result in any hourly increases in pollutant emissions when compared to firing No. 2 fuel oil in the CCCT of Unit 1. Consequently, the Department agrees with the applicant that the oil-to-natural gas conversion project does not constitute a modification under NSPS rules.

3.2.1.2 *NSPS Applicable to Stationary Gas Turbines*

NSPS Subpart GG applies to stationary gas turbines that commence construction, modification or reconstruction after October 3, 1977, and that have a heat input at peak load equal to or greater than 10 MMBtu/hr. The CCCT of Unit 1 was constructed after October 3, 1977 and has a heat input at peak load greater than 10 MMBtu/hr. Unit 1 will therefore remain subject to NSPS Subpart GG following the use of natural gas instead of No. 2 fuel oil as a back-up fuel and the addition of natural gas as an

augmentation fuel. The NSPS Subpart GG emission standards for NO_X and SO_2 are not fuel specific and will therefore remain unchanged for Unit 1.

NSPS Subpart KKKK applies to stationary combustion turbines that commence construction, modification or reconstruction after February 18, 2005, and that have a heat input at peak load equal to greater than 10 MMBtu/hr. The CCCT of Unit 1 has a heat input at peak load greater than 10 MMBtu/hr. However, as previously discussed, the planned changes to Unit 1 do not constitute a *modification* or *reconstruction* as defined by NSPS Subpart A. Consequently, Subpart KKKK does not apply to the CCCT.

3.2.1.3 *NSPS Subpart Db - Industrial-Commercial-Institutional Steam Generating Units*

NSPS Subpart Db applies to steam generating units that commence construction, modification or reconstruction after June 19, 1984, and that have a heat input capacity greater than 100 MMBtu/hr heat input of fossil fuel. According to the applicant, the auxiliary boiler was constructed after June 19, 1984 and has a heat input greater than 100 MMBtu/hr. The auxiliary boiler will therefore remain subject to NSPS Subpart Db following its conversion to natural gas.

The only applicable NSPS Subpart Db emission standard for natural gas fired units is a NO_X emission limit of 0.10 lb/MMBtu for low heat release rate boilers. Low heat release rate is defined by NSPS Subpart Db as heat release rate of 70,000 Btu/hr-ft^2 or less. According to the applicant, the auxiliary boiler will remain a low heat release rate unit following its conversion to natural gas fuel. Consequently, the current permitted NO_X emission limit of 0.10 lb NO_X/MMBtu is for the auxiliary boiler will not change as a result of this permitting action.

3.2.2 <u>NESHAP Applicability</u>

NESHAP potentially relevant to the oil-to-natural gas conversion project emission units are discussed in the following subsections.

3.2.2.1 *NESHAP Subpart DDDDD – Major Sources, Industrial-Commercial-Institutional Boilers and Process Heaters*

EPA issued a revised final NESHAP Subpart DDDDD on May 21, 2011. However, on the same day EPA also published a notice announcing its intent to reconsider certain provisions of the final rule. On December 23, 2011, EPA issued a proposed NESHAP Subpart DDDDD regarding its reconsideration of the May 21, 2011 final NESHAP. As proposed, NSPS Subpart DDDDD would only apply to new and existing industrial boilers and process heaters located at major HAP sources. Since the Polk Power Station is not a major HAP source, it is <u>not</u> be subject to the final or proposed NESHAP Subpart DDDDD.

3.2.2.2 *NESHAP Subpart JJJJJJ - Area Sources, Industrial-Commercial-Institutional Boilers*

NESHAPS Subpart JJJJJJ was promulgated by EPA as a final rule on March 21, 2011. The rule applies to new and existing industrial, commercial, and institutional boilers located at area HAP sources. The Polk Power Station is classified as an area HAP source. However, NESHAPS Subpart JJJJJJ §63.11195(e) specifically exempts gas-fired boilers. A gas-fired boiler is defined by §63.11237 as:

"… any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel".

Accordingly, the auxiliary boiler following conversion to natural gas fuel will <u>not</u> be subject to the requirements of NESHAPS Subpart JJJJJJ.

3.2.2.2 *NESHAP Subpart UUUUU – Coal and Oil Fired Electric Utility Steam Generating Units*

NESHAPS Subpart UUUUU applies to new and existing coal- and oil-fired electric generating units. As an existing EGU, Unit 1 will need to comply with the applicable requirements of NESHAP Subpart UUUUU no later than April 16, 2015. For existing IGCC units, NESHAPS Subpart UUUUU contains emission standards for filterable particulate matter (PM) [or alternatively total non-Hg HAP metals or individual HAP metals], HCl, and Hg.

4. REQUIRED PERMIT CHANGES AND OTHER MODIFICATIONS

4.1 Project 1

The following discussion for Project 1 is broken into the applicant's requested changes by EU followed by the Departments' response to each requested change.

4.1.1 Fuel Oil Sulfur Content, SO_2 Averaging Time and SO_2 Emissions – Auxiliary Boiler (EU 003)

4.1.1.1 *Applicant Request*

Currently, daily monitoring of fuel oil is required to ensure its sulfur content is less than or equal to 0.05% by weight on a daily basis whenever fuel oil is fired in the auxiliary boiler (EU 003). The applicant requests that the daily monitoring requirement for the auxiliary boiler be replaced by a monthly composite sample from each fuel delivery consistent with the Federal guidelines contained within NSPS Subpart Db. In addition, the applicant also requested that the 30-day averaging period for SO_2 emissions and the SO_2 emission limit for the auxiliary boiler be removed.

In comments submitted on June 21, 2012 by the applicant on the draft air construction permit and draft/proposed Title V air permit revision package issued on May 9, 2012, it was requested that vendor certification of the fuel oil sulfur content be allowed to show compliance with the fuel oil sulfur content. In lieu of vendor certification, the applicant requested that a composite sampling procedure approved by the Administrator pursuant to 40 CFR 75.66 be allowed. The applicant requested that the fuel contract and bills of lading be used to demonstrate compliance for the vendor certification. For fuel oil sampling, the applicant requested that a monthly composite sample be prepared from each fuel oil delivery (lot) to the storage tanks, with the sample analyzed in the laboratory for density, heat content and sulfur content.

4.1.1.2 *Department Response*

As stated in Title (§) 40 CFR 60.42b(e), "*Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis"*. This required the daily monitoring of the fuel oil sulfur content when oil is fired in the auxiliary boiler in order to calculate the 30-day rolling average for compliance purposes. However, §40 CFR 60.42b(f) provides an exception to this daily sulfur content monitoring requirement that is in §40 CFR 60.42b(j)(2). In §40 CFR 60.42b(j)(2), for very low sulfur fuel, compliance with SO_2 emission limits and fuel sulfur content can be met by maintaining fuel records as described in §60.49b(r). Very low sulfur fuel is defined in §40 CFR 60.41b for units constructed, reconstructed, or modified on or before February 28, 2005 as oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 nanograms per joule (ng/J) (0.5 pound/MMBtu) heat input. The auxiliary boiler at the Polk Power Station is limited to firing fuel oil with a maximum sulfur content of 0.05% by weight which meets the weight requirement and also meets the emission requirement as shown below by assuming a heat content for No. 2 fuel oil (FO) of 19,673 Btu/lb.

$$\{(1{,}000{,}000 \text{ Btu/hr}) / (19{,}673 \text{ Btu FO/lb})\} \times (0.0005 \text{ lb S/lb FO}) \times 2 \text{ lb } SO_2\text{/lb S}) = 0.051 \text{ lb } SO_2\text{/MMBtu}$$

§60.49b(r) states, *"The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected*

facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit".

The Department agrees that daily sampling of the fuel oil for sulfur content when fired in the auxiliary boiler is not required to meet the fuel oil sulfur monitoring requirements of NSPS Subpart Db as long as a vendor certification of fuel oil deliveries show that the oil meets the 0.05% sulfur content by weight requirement. As requested by the applicant, in lieu of vendor certification, the Department will allow the fuel oil sulfur content to be measured by a monthly composite sample of fuel oil deliveries to the storage tanks.

The new "clean" PSD permit for Unit 1 (PSD-FL-194J) will include this new fuel oil sulfur monitoring procedure and the allowance for vendor certification. In addition, in the new PSD permit for Unit 1, the requirement for SO_2 emission testing for the auxiliary boiler will be removed along with the 30-day averaging time since the current BACT emission limit of 0.80 lb SO_2/MMBtu is more than an order of magnitude higher than the theoretical maximum SO_2 emissions from the boiler. The 0.80 lb/MMBtu limit is a requirement of §60.42b(a) & (j) which are no longer applicable due to the very low sulfur fuel oil records requirements of §60.49b(r).

4.1.2 Permitted Capacity of Solid Fuels Gasification Plant (EU 006)

4.1.2.1 *Applicant Request*

The applicant requests that under authorized fuels that the limits for tons per day of petcoke and total tons per day of feed to the solid fuel gasification plant be removed and only the 85% coal/petcoke blend limitation remain. The applicant also requests that the petcoke tonnage limit be removed from the recordkeeping requirements.

4.1.2.2 *Department Response*

Since 85% of the total weight limit of 2,325 tons per day of coal/petcoke fed to solid fuel gasification plant equals the 1,976 tons per day of petcoke limit, the petcoke weight limit is redundant and can be removed. In addition, the current permitted capacity for the solid fuel gasification system of 2,325 tons per day will now be reflected in a permitting note. The Department also agrees that the recordkeeping requirement should be changed to come into conformity with the new authorized fuels requirement with only the total daily total tonnage of solid fuel to the gasifier required and will make the appropriate changes. Permit PSD-FL-194J will include the revised language and the Title V permit will be revised accordingly.

4.1.3 Nitrogen Oxide NO_X Emissions When Firing Natural Gas and Fuel Oil (EU 009 and 010)

4.1.3.1 *Applicant Request*

The applicant requested that when firing natural gas in the turbines that the NO_2 testing requirement be removed since these units have been in operation for years, emissions are monitored continuously by CEMS, and initial "new and clean" GE performance stack test are no longer applicable. The applicant also requests that the reasonable measures requirement to achieve a NO_X concentration of 9 ppmvd @ 15% O_2 involving tuning of the combustors for Dry Low NO_X operation while firing gas be removed since the initial tuning has already been accomplished.

The applicant also requested that when firing fuel oil in the turbines that the reasonable measures requirement to achieve a NO_X concentration of 42 ppmvd @ 15% O_2 be removed since a NO_X reduction plan has already been submitted to the Department. The applicant has also requested that on fuel oil firing be limited to 750 hour per year. Finally, the applicant request that the vendor certification requirement for the sulfur content of the fuel oil sulfur fired in the turbines be supplemented by fuel oil sulfur monitoring utilizing composite samples analyzed in an on-site or off-site laboratory.

4.1.3.2 Department Response

The Department agrees with the applicant requests with regard to the natural gas NO_2 testing and the reasonable measures requirements. Also fuel oil firing will be limited to 750 hours per year as requested. The appropriate permit conditions in permit PSD-FL-263B (Project No. 1050233-030-AC).

The Department agrees with the applicant's request with regard to the fuel oil reasonable measures requirements with regard to NO_X. With regard to fuel oil sulfur monitoring, the Department also agrees with the applicant. The Department will also stipulate that the monthly composite sample be analyzed in an on-site or off-site laboratory for density, heat content, sulfur content and carbon content. Vendor certification can also be used to show compliance. The appropriate permit conditions in permit PSD-FL-263B (Project No. 1050233-030-AC).

4.2 Project 2

As previously described, the applicant has requested that natural gas replace No. 2 fuel oil as the startup and backup fuel for the combined cycle CCCT (EU 001) and as the only allowable fuel in the auxiliary boiler (EU 003). In addition, the applicant requested that natural gas replace propane as the burner fuel for the SAP (EU 004) and solid fuel gasification system (EU 006).

4.2.1 Natural Gas Conversion

The conversion to natural gas involves emissions limit changes and compliance requirements for the CCCT and auxiliary boiler. However, the conversion does not result any increase in hourly emission rates from either emission unit. Propane is currently utilized in the SAP H_2S to SO_2 conversion furnace burners and SO_2 to SO_3 converter preheater burners and in the preheater burners utilized in the solid fuel gasifier preheater. These burners will be converted to natural gas. The heat inputs to both the SAP burners and solid fuel gasification system burners will not change as a result of their conversion from propane to natural gas and emissions should not be affected

The conversion to natural gas for each affected emission unit will be incorporated into permit PSD-FL-194J accordingly. In addition, language on the new syngas/natural gas burner configuration, along with the corresponding NO_X emission control technology will also be included.

4.2.2 Heat Input Rates

Currently, the CCCT is limited to a maximum heat input rating of 1,755 MMBtu/hr when firing natural gas/syngas and 1,765 MMBtu/hr when firing No. 2 fuel oil. The applicant requested a nominal rating of 1,642 MMBtu/hr when firing syngas, natural gas or syngas augmented by natural gas with a 10% contingency. The applicant subsequently requested that the heat input rates limits to the CCCT be changed from a high heat value (HHV) basis to a lower heating value (LHV) basis. Based on information provided by the applicant, the conversions ratio (LHV/HHV) for syngas is 0.9355. The Department found information from the U.S. Department of Energy, Hydrogen Analysis Resource Center[1] that stated that the conversion ration of low sulfur fuel oil is 0.93 and 0.91 for natural gas. To convert the previous allowable heat input rates of 1,755 MMBtu/hr (syngas) and 1,765 MMBtu/hr (fuel oil) to a LHV basis you obtain (assume heat input for fuel oil for natural gas):

- Syngas (LHV) = 1,755 MMBtu/hr x 0.9355 = 1,641.8 MMBtu/hr, use 1,642 MMBtu/hr
- Fuel Oil (LHV) = 1,765 MMBtu/hr x 0.93 = 1,641.5 MMBtu/hr, also use 1,642 MMBtu/hr
- Natural Gas (LHV) = 1,765 MMBtu/hr x 0.91 = 1,606,15 MMBtu/hr which is ~2% less than 1,642 MMBtu/hr, use 1,642 MMBtu/hr

The applicant's request represents a potential increase in the maximum heat input rate. The Department will authorize a permitted heat input rate to the CCCT of 1,642 MMBtu/hr when firing syngas, syngas augmented by natural gas, natural gas alone, or No. 2 fuel oil alone. This heat input rate will be based on a compressor inlet temperature of 59 ºF, fuel temperature of 619°F, diluent temperature

[1] http://hydrogen.pnl.gov/cocoon/morf/hydrogen/site_specific/fuel_heating_calculator?canprint=false

of 616°F, no air extraction, and based and the lower heating value (LHV) of each fuel. In addition, the Department will required for compliance testing purposes that initial and annual tests shall be conducted at 90% or greater of the permitted heat input rate. If it is impracticable to test within the described range, the unit may be tested at less than the described range; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Based on these requirements, there will be no increase in the maximum hourly emission rates and no new NSPS provisions will be triggered.

4.3 DLN Tuning (Units 4 and 5)

TECO made a request to modify the DLN tuning requirements for the simple cycle gas-fired turbine Units 4 and 5. Specifically, TECO requested that the reporting of excess NO_X emissions on a quarterly basis be required and that the requirement to notify the Compliance Authority at least one day in advance with details of the activity and a proposed tuning schedule be removed. To accomplish these changes, the appropriate permit conditions in permit PSD-FL-363B (Project No. 1050233-030-AC).

5. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed 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, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. David Read is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Office of Permitting and Compliance at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.