Florida Department of Environmental Protection

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PERMITTEE

Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

Air Permit No. 0570039-084-AC
Permit Expires: March 31, 2021
Minor Air Construction Permit

Authorized Representative:
Mr. Byron Burrows, Manager – Air Programs

Big Bend Station
Modification to Units 1 – 4
Igniters and Process Heater Projects

PROJECT

This is the final air construction permit, which authorizes the modification to the monitoring and recordkeeping requirements for the natural gas igniters and process heaters. The proposed work will be conducted at the existing Big Bend Station, which is an electric power facility categorized under Standard Industrial Classification No. 4911. The existing facility is located in Hillsborough County at 13031 Wyandotte Road in Apollo Beach, Florida. The UTM coordinates are Zone 17, 363.15 kilometers (km) East and 3074.91 km North.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); and Section 4 (Appendices). Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of Section 4 of this permit.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and is not subject to the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

David L Read

David Lyle Read, P.E.
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For:

Jeffery F. Koerner, Deputy Director
Division of Air Resource Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Construction Permit package was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on the date indicated below to the following persons.

Mr. Byron Burrows, TEC: btburrows@tecoenergy.com
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Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

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FACILITY DESCRIPTION

The Tampa Electric Company (TEC) Big Bend Station is a nominal 1,892 megawatt (MW) electric generation facility. This facility consists of four fossil fuel fired boiler electrical generating Units 1 – 4 (EU 001 – EU 004); four steam turbine electrical generators (STEG); two simple-cycle combustion turbine (SCCT) 4A and 4B (EU 041 and EU 042) sharing a common electrical generator; solid fuels, fly ash, limestone, gypsum, slag, bottom ash storage and handling facilities; and, fuel oil storage tanks.

Units 1 through 4 have a combined electrical generating output of 1,821 MW. Units 1 through 3 each have a design electrical generating capacity of 445 MW. Unit 4 has a design electrical generating capacity of 486 MW. The fuel fired in all four units consists of coal, or a coal/petroleum coke blend containing a maximum of 20% petroleum coke by weight, or coal blended with coal residual generated from the Polk Power Station, or a coal/petroleum coke blend further blended with coal residual generated from the Polk Power Station, and on-site generated fly ash. In addition to the fuels allowed to be burned during normal operation, each unit burns new No. 2 fuel oil during startup, shutdown, flame stabilization, and during the startup of an additional solid fuel mill on an already operating unit.

For each unit, nitrogen oxide (NO_X) emissions are controlled by low-NO_X burners (LNB) and a selective catalytic reduction (SCR) system. Unit 4 also has a separated over fire air system (SOFA) system to further control NO_X emissions. Particulate matter (PM) emissions are controlled by a dry electrostatic precipitator (ESP) while sulfur dioxide (SO_2) emissions are controlled by wet flue gas desulfurization (FGD) system on each unit. Continuous opacity monitoring systems (COMS) are used to measure opacity. Units 1 through 3 are equipped with continuous emissions monitoring systems (CEMS) to measure NO_X, SO_2, and carbon dioxide (CO_2). Unit 4 is equipped with CEMS to measure carbon monoxide (CO), NO_X, SO_2, and CO_2. These units began operation in 1970 (Unit 1), 1973 (Unit 2), 1976 (Unit 3), and 1985 (Unit 4).

The SCCT 4A and 4B (EU 041 and EU 042) consist of one PWPS FT8-3® SwiftPac® aero-derivative SCCT-electrical generator to operate in simple cycle mode. The SwiftPac® consists of two combustion turbines coupled to one common generator having a nominal gross generation capacity of 62 MW. Each SCCT is allowed to fire pipeline-quality natural gas and ultra-low sulfur distillate (ULSD) fuel oil. Each SCCT is equipped with water injection to minimize NO_X emissions and an oxidation catalyst to minimize CO and volatile organic compounds (VOC) emissions.

PROPOSED PROJECT

TEC is requesting modification of the monitoring and recordkeeping requirements in air construction Permit Nos. 0570039-065-AC and 0570039-070-AC. Specifically, TEC is requesting to remove the annual VOC testing requirement from Big Bend Units 1-4, revise the natural gas recordkeeping requirements, remove the VE testing requirement from the process heaters, and revise the method of calculation for the actual NO_X emissions from the process heaters. More details of the proposed project can be found in the Technical Evaluation and Preliminary Determination. The conditions of this air construction permit supercede the specific conditions of Permits 0570039-065-AC and 0570039-070-AC.

This project will modify the following emissions units.

Facility ID No. 0570039	
ID No.	**Emission Unit Description**
001	Fossil Fuel Fired Steam Generator Unit No. 1
002	Fossil Fuel Fired Steam Generator Unit No. 2
003	Fossil Fuel Fired Steam Generator Unit No. 3
004	Fossil Fuel Fired Steam Generator Unit No. 4
051	Two 6 MMBtu/hr Natural Gas-fired Process Heaters

FACILITY REGULATORY CLASSIFICATION

- The facility is 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 62-213, 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 does operate units subject to the New Source Performance Standards (NSPS) of 40 Code of Federal (CFR) 60.
- The facility does operate units subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) of 40 CFR 63.
- The facility operates units subject to the Federal Clean Air Interstate Rule (CAIR) in accordance with Rule 62-296.470, F.A.C.

RELEVANT DOCUMENTS

Several documents shown in the following link are not a part of this permit, but helped form the basis for this permitting action. Documents related to this permitting action are posted under Permit No. 0570039-084-AC at the following web site address: http://appprod.dep.state.fl.us/air/emission/apds/default.asp

1. Permitting Authority: The permitting authority for this project is the Office of Permitting and Compliance in the Division of Air Resource Management of the Department of Environmental Protection (Department). The Office of Permitting and Compliance mailing address is 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Environmental Protection Commission of Hillsborough County at: 3629 Queen Palm Drive, Tampa, Florida 33619. Phone: (813) 627-2600.
3. Appendices: The following Appendices are attached as a part of this permit: Appendix A (Citation Formats and Glossary of Common Terms); Appendix B (General Conditions); Appendix C (Common Conditions); Appendix D (Common Testing Requirements); Appendix E (NESHAP Subpart A); and Appendix F (NESHAP Subpart DDDDD).
4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296 and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No new emissions unit shall be constructed and no existing emissions unit shall be modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
7. Construction and Expiration. The expiration date shown on the first page of this permit provides time to complete the physical construction activities authorized by this permit, complete any necessary compliance testing, and obtain an operation permit. Notwithstanding this expiration date, all specific emissions limitations and operating requirements established by this permit shall remain in effect until the facility or emissions unit is permanently shut down. For good cause, the permittee may request that that a permit be extended. Pursuant to Rule 62-4.080(3), F.A.C., such a request shall be submitted to the Permitting Authority in writing before the permit expires. [Rules 62-4.070(4), 62-4.080 & 62-210.300(1), F.A.C.]
8. Source Obligation:

a. Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

b. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

c. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

9. Application for Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V air operation permit is required for regular operation of the permitted emissions units. The permittee shall apply for a Title V air operation permit revision at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation of the combined natural gas igniter and process heater projects. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050 and Chapter 62-213, F.A.C.]

10. Actual Emissions Reporting: This permit is based on an analysis that compared baseline actual emissions with projected actual emissions and avoided the requirements of subsection 62-212.400(4) through (12), F.A.C. for several pollutants. Therefore, pursuant to Rule 62-212.300(1)(e), F.A.C., the permittee is subject to the following monitoring, reporting and recordkeeping provisions. *{Permitting Note: For this project, the permit requires the annual reporting of actual NO_X emissions for the following units: Fossil Fuel Fired Steam Generating Units 1 - 4 (Emissions Units 001 - 004), and the Two 6 MMBtu/hr Natural Gas-fired Process Heaters (Emissions Unit 051).}*

a. The permittee shall monitor the emissions of any PSD pollutant that the Department identifies could increase as a result of the construction or modification and that is emitted by any emissions unit that could be affected; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 calendar years following the year in which resumption of regular operations after the change occurred. Emissions shall be computed in accordance with the provisions in Rule 62-210.370, F.A.C., which are provided in Appendix C of this permit.

b. The permittee shall report to the Department within 60 days after the end of each calendar year during the 5-year period setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:

   1) The name, address and telephone number of the owner or operator of the major stationary source;
   2) The annual emissions calculations pursuant to the provisions of 62-210.370, F.A.C., which are provided in Appendix C of this permit;
   3) If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and
   4) Any other information that the owner or operator wishes to include in the report.

c. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1 and 2, F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

d. The permittee shall compute and report annual emissions in accordance with Rule 62-210.370(2), F.A.C. as provided by Appendix C of this permit. For this project, the permittee shall use the following methods in reporting the actual annual NOx emissions for Units 1 – 4 and the two 6 MMBtu/hour Process Heaters:

(1) The permittee shall use data collected from the CEMS to determine and report the actual annual emissions of NOx for Units 1 – 4 during all operating modes firing natural gas.

(2) When calculating the actual annual emissions of NO_X for the process heaters, the permittee shall use the following information: the actual annual heat input rates; and, the site-specific or vendor NO_X emission factor, whichever is greater. The total actual annual NO_X emissions from the process heaters shall be added to the NO_X CEMS data from Units 1 – 4 in d.(1) above and compared to the emission cap in **Specific Condition B.8.** of this permit to determine and report the actual annual emissions of NO_X from this project.

(3) Unless otherwise approved by the Department, the permittee shall use the average of the reported 2013 and 2014 Annual Operating Report data for Units 1 - 4 as the baseline actual emissions.

(4) As defined in Rule 62-210.370(2), F.A.C., the permittee shall use a more accurate methodology if it becomes available.

{Permitting Note: Baseline emissions of NO_X were determined to be 4,842.9 tons/year, and projected actual emissions of NO_X were determined to be 4,882 tons/year.}

[Application No. 0570039-084-AC; and Rules 62-212.300(1)(e) and 62-210.370, F.A.C.]

A. Fossil Fuel Fired Steam Generator Units 1 – 4 (EU 001 – EU 004)

This section of the permit addresses the following emissions units.

EU No.	Emission Unit Description
001	Fossil Fuel Fired Steam Generator Unit No. 1
002	Fossil Fuel Fired Steam Generator Unit No. 2
003	Fossil Fuel Fired Steam Generator Unit No. 3
004	Fossil Fuel Fired Steam Generator Unit No. 4

Units 1 through 3 each have a design electrical generating capacity of 445 MW. Unit 4 has a design electrical generating capacity of 486 MW. The fuel fired in all four units consists of coal, or a coal/petroleum coke blend containing a maximum of 20% petroleum coke by weight, or coal blended with coal residual generated from the Polk Power Station, or a coal/petroleum coke blend further blended with coal residual generated from the Polk Power Station, and on-site generated fly ash. In addition to the fuels allowed to be burned during normal operation, each unit burns new No. 2 fuel oil during startup, shutdown, flame stabilization, and during the startup of an additional solid fuel mill on an already operating unit. Upon completion of this project, Units 1 through 4 will have the capability to fire natural gas during startup, shutdown, flame stabilization, low-load conditions, and will have the capability to co-fire natural gas with coal during normal operations. Once the shakedown of the natural gas igniter system is complete, the firing of fuel oil will be discontinued.

For each unit, nitrogen oxide (NO_X) emissions are controlled by low-NO_X burners and a selective catalytic reduction system, particulate matter (PM) emissions are controlled by a dry electrostatic precipitator, and sulfur dioxide (SO_2) emissions are controlled by wet flue gas desulfurization (FGD). Unit 4 also has a separate over-fire air system to further control NO_X emissions. Continuous opacity monitoring systems (COMS) are used to measure opacity. Units 1 through 4 are equipped with continuous emissions monitoring systems (CEMS) to measure NO_X, SO_2, and carbon dioxide (CO_2). Unit 4 is also equipped with CEMS to measure carbon monoxide (CO). These units began operation in 1970 (Unit 1), 1973 (Unit 2), 1976 (Unit 3), and 1985 (Unit 4).

{Permitting Note: Fossil Fuel Fired Steam Generator Units 1 - 4 are regulated under: the federal Acid Rain Program for Phase II SO_2 and NO_X; Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; Rule 62-296.700(6), F.A.C., Reasonable Available Control Technology (RACT) PM – Operation and Maintenance Plan; Compliance Assurance Monitoring, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; Rule 62-296.470, F.A.C., Clean Air Interstate Rule; and NESHAP Subpart UUUUU, the Mercury and Air Toxics Standards, in 40 CFR 63. Unit 4 is also regulated under NSPS Subpart Da of 40 CFR 60, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(8)(b)2., F.A.C.; Rule 212.400, F.A.C., PSD.}

PREVIOUS APPLICABLE REQUIREMENTS

1. Other Permits: The conditions of this permit supersede all previously issued air construction permits for the natural gas igniter and process heater projects (Permit Nos. 0570039-065-AC, -070-AC, -073-AC, -078-AC, and -081-AC). Unless otherwise specified, these conditions replace all other applicable permit conditions and regulations. [Rule 62-4.070, F.A.C.]

EQUIPMENT

2. Fossil Fuel Fired Steam Generator Units 1 - 4: The permittee is authorized to remove the existing fuel oil igniters and to install natural gas igniters, natural gas igniter piping and valve station, modify and upgrade the Burner Management System and associated equipment for Units 1 - 4 in order to burn natural gas instead of fuel oil during startup, shutdown, flame stabilization and as a supplemental fuel. [Permit No. 0570039-065-AC and Rule 62-212.300(1)(a), F.A.C.]

PERFORMANCE RESTRICTIONS

3. Design and Permitted Capacities:

   a. Design Capacity: The design heat input rate from the combustion of coal or coal and natural gas combined are as follows:

Unit No.	Heat Input MMBtu/hour
1	4,037
2	3,996
3	4,115
4	4,330

   {Permitting Note: These design heat input rates are based on the original design of each unit for firing coal with a certain lower heating value (LHV) that was used to design each boiler. At any given time, the actual heat input rate is a function of the actual demand load, the coal mass firing rate, and the fuel properties of the coal being fired at that time. Although the above design capacity is not intended as an operational restriction, the permittee shall obtain the appropriate air construction permits before making any physical or operational changes that would increase the actual heat input rate capability of the units.}

   b. Permitted Capacity:

      (1) Co-firing Natural Gas: The total annual heat input to Units 1 – 4 from co-firing coal/solid fossil fuel and natural gas shall not exceed 108,210,630 million British thermal units (MMBtu) during any calendar year.

      (2) Low-Load Natural Gas: The annual heat input to Units 1 – 4 from firing natural gas during the low-load natural gas-only operation shall not exceed 1,514,460 million British thermal units (MMBtu) during any calendar year.

   {Permitting Note: The higher heating value (HHV) of coal is approximately 23.6 MMBtu/tons of coal and the natural gas HHV is approximately 1,020 MMBtu/million cubic feet of gas. Low-load natural gas firing is when the SCR controls are not at optimum operating conditions and this heat input limit does not include natural gas fired during startup, shutdown and flame stabilization.}

   [Rules 62-4.160(2), 62-210.200(PTE), 62-212.300(1)(e), and 62-296.405(1), F.A.C.; Permit No. 0570039-065-AC; and Application No. 0570039-084-AC]

4. Authorized Fuels:

   a. *Coal and Coal Blends.*

      (1) Coal is the primary fuel burned in Units 1 - 4.

      (2) Coal and Coal Blends: Units 1 – 4 are authorized to burn coal, or a coal/petroleum coke blend, or coal blended with raw coal residual, or a coal/petroleum coke blend further blended with raw coal residual. In any case, the petroleum coke content of any fuel blend shall not exceed 20% by weight during normal operation.

      (3) Raw Coal Residual: The proposed work shall not increase the permitted firing of 200 tons/day of raw coal residual in Units 1 - 4 combined.

      (4) Fly Ash Residual: Units 1 – 4 are authorized to re-inject on-site generated fly ash residual for energy.

b. *Natural Gas.*

(1) Natural gas is authorized to be fired during low-load operation, startup, shutdown, flame stabilization, and during the start of an additional solid fuel mill on an already operating unit.

(2) Natural gas is authorized to be fired in combination with coal/solid fossil fuel during normal operation as a supplemental fuel.

{Permitting note: During normal operation the SCR controls will be in use.}

[Rule 62-210.200(PTE), F.A.C.; Permit Nos. 0570039-053-AC and 0570039-065-AC]

5. Restricted Operation: The hours of operation are not limited (8,760 hours per year). [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

TESTING REQUIREMENTS

6. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit, unless the Department obtains other information sufficient to demonstrate compliance. The owner or operator of the emissions unit shall provide a report on the results of said tests to the Department in accordance with the provisions of subsection 62-297.310(10), F.A.C. *{Permitting note: This condition does not impose a specific testing requirement.}*

[Rule 62-297.310(8)(c), F.A.C.]

7. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

8. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
7E	Determination of Nitrogen Oxides Emissions From Stationary Sources (Instrumental Analyzer Procedure)
18	Measurement of Gaseous Organic Compound Emissions By Gas Chromatography
25	Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

The above methods are described in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

RECORDS AND REPORTS

9. Operational Records: To demonstrate compliance with the operational restrictions in **Specific Condition A.3.b.**, the permittee shall establish and maintain the following records from the firing of natural gas and solid fuel in steam generator Units 1 - 4:

a. Record the monthly total heat input rate from the co-firing of natural gas and solid fuel;

b. Record the monthly natural gas heat input rate from the firing of natural gas during the low-load natural gas-only operation;

c. The standard heating value of natural gas, 1,020 Btu/scf, shall be used to calculate the monthly natural gas heat input;

d. The methods set forth in the current Title V permit for determining the heat input of solid fuels shall be used to calculate the monthly heat input from solid fuel during co-firing operations;

e. Within 30 calendar days following the end of each month, calculate and record the heat inputs for a. and b. above. The calendar year total heat inputs for a. and b. shall be calculated and recorded within 60 days of the end of the calendar year.

[Rule 62-4.070(3), F.A.C. and Title V Permit No. 0570039-072-AV]

B. Two 6 MMBtu/hr Natural Gas-fired Process Heaters

This section of the permit addresses the following emissions unit.

EU No.	Emission Unit Description
051	Two 6 MMBtu/hr Natural Gas-fired Process Heaters

{Permitting Note: In accordance with Rule 62-212.400(12), F.A.C., other emissions standards and performance restrictions specified in this permit allow the emission units to avoid PSD preconstruction review for NO_X. The process heaters are regulated under NESHAP Subpart DDDDD (Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters) of 40 CFR 63 adopted and incorporated by reference in Rule 62-204.800, F.A.C.}

PREVIOUS APPLICABLE REQUIREMENTS

1. Other Permits: The conditions of this permit supercede all previously issued air construction permits for the natural gas igniter and process heater projects (Permit Nos. 0570039-065-AC, -070-AC, -073-AC, -078-AC, and -081-AC). Unless otherwise specified, these conditions replace all other applicable permit conditions and regulations. [Rule 62-4.070, F.A.C.]

EQUIPMENT

2. Process Heaters: The permittee is authorized to install and operate two process heaters that will fire natural gas with a maximum heat input rate of 6 million British Thermal Units per hour (MMBtu/hr). Each process heater shall be equipped with a gas flow meter to monitor the actual natural gas heat input rate to each process heater. [Application No. 0570039-084-AC; and, Rule 62-212.400(12), F.A.C. to avoid PSD preconstruction review for NO_X]

PERFORMANCE RESTRICTIONS

3. Permitted Capacity: The process heaters shall be designed and operated with a maximum heat input rate of 6 MMBtu/hr. [Permit No. 0570039-070-AC, Application No. 0570039-084-AC; and, Rule 62-210.200(PTE), F.A.C.]

4. Authorized Fuel: The process heaters shall fire only pipeline quality natural gas. [Permit No. 0570039-070-AC, Application No. 0570039-084-AC; and, Rule 62-210.200(PTE), F.A.C.]

5. Hours of Operation: The hours of operation for the process heaters are not limited (8,760 hours per year). [Rule 62-210.200(PTE), F.A.C.]

6. Applicable NESHAP Provisions: The process heaters are subject to, and shall comply with, the applicable provisions in NESHAP Subpart A (General Provisions) and NESHAP Subpart DDDDD (Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters) of 40 CFR 63, which are identified in Appendix E and F of this permit. [NESHAP Subparts A and DDDDD in 40 CFR 63; and, Rule 62-204.800, F.A.C.]

EMISSIONS STANDARDS

7. Visible Emissions: Visible emissions from each process heater shall not exceed 20% opacity. This condition does not impose a specific visible emissions testing requirement. [Rule 62-296.320(4)(b)1., F.A.C.]

8. NO_X Emissions Cap: The net emissions increase of NO_X from the combustion sources in this project (EU 001 - EU 004 and EU 051, combined) shall not exceed 39.1 tons per year. Compliance with this NO_X emissions cap shall be demonstrated on a calendar year basis using the following equation:

$$[\text{Units } 1 - 4_{CEMS}] + [(EF_{heater})(\text{Heater1}_{heat\ input} + \text{Heater2}_{heat\ input})\ (\text{ton}/2000\ \text{lb})] \leq 39.1\ \text{TPY},\ NO_X$$

Where:

[Units 1 – 4_{CEMS}] = Calendar year total of combined NO_X emissions in TPY from Units 1-4 from data collected from the CEMS during all operating modes firing natural gas minus baseline actual emissions of 4,842.9 TPY. Emissions generated from the coal/solid fossil fuel-only mode of operation shall be excluded from this term.

EF_{heater} = NO_X emission factor (lb/MMBtu) from site-specific stack test or vendor (0.088 lb/MMBtu), whichever is greater

NG_{HHV} = Natural gas higher heating value (HHV) of 1,020 in Btu/scf as specified in AP-42 Table 1.4-1.

$Heater_{heat\ input}$ = Calendar year total of heat input for each process heater

If necessary, the permittee shall adjust the operation of the process heaters to comply with the NO_X emissions cap. [Rule 62-212.400(12), F.A.C. to avoid PSD preconstruction review for NO_X]

9. PM Emissions: The emissions of PM shall be minimized by firing pipeline quality natural gas exclusively. [Rule 62-210.200(PTE), F.A.C.]

10. SO_2 Emissions: The emissions of SO_2 shall be minimized by firing pipeline quality natural gas exclusively. [Rule 62-210.200(PTE), F.A.C.]

TESTING AND COMPLIANCE REQUIREMENTS

11. Initial Compliance Tests: Each process heater shall be tested to demonstrate initial compliance with the emissions standards for NO_X. The initial tests shall be conducted within 60 days of the completion of all igniter projects (Units 1 to 4), but no later than 180 days after completion of the last igniter project (Unit 1). Testing is only required on one burner of each process heater and should occur at full load (3 MMBtu/hr). Compliance testing shall consist of three 1-hour test runs. [Rules 62-4.070(3), 62-212.400(12), F.A.C. to avoid PSD preconstruction review for NO_X and 62-297.310(7)(a)1, F.A.C., 0570039-078-AC]

12. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit, unless the Department obtains other information sufficient to demonstrate compliance. The owner or operator of the emissions unit shall provide a report on the results of said tests to the Department in accordance with the provisions of subsection 62-297.310(10), F.A.C. [Rule 62-297.310(8)(c), F.A.C.]

13. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix D (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

14. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources

The above methods are described in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

MONITORING REQUIREMENTS

15. Gas Flow Meter: Each process heater shall be equipped with a gas flow meter to monitor the actual natural gas flow rate to each process heater. [Rule 62-4.070(3), F.A.C.]

RECORDKEEPING AND REPORTING

16. Work Practice Standards: Each process heater shall conduct a biennial tune-up every 2-years and maintain on-site and submit, if requested by the Department, an annual report in accordance with NESHAP Subpart DDDDD of 40 CFR 63. All recordkeeping requirements shall meet the following:
    a. Your records must be in a form suitable and readily available for expeditious review.
    b. You must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
    c. You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2-years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. You can keep the records off site for the remaining 3 years.

    [NESHAP Subparts A and DDDDD in 40 CFR 63; and, Rule 62-204.800, F.A.C.]

17. Operational Records: To demonstrate compliance with the operational restrictions in **Specific Condition B.3.** and the NO_X emission cap in **Specific Condition B.8.**, the permittee shall establish and maintain the following records when natural gas is fired in the process heaters:
    a. Record the monthly natural gas heat input (MMBtu) of each process heater;
    b. The standard heating value of natural gas, 1,020 Btu/scf, shall be used to calculate the monthly heat input;
    c. Record the calculated monthly and calendar year total emissions of NO_X to demonstrate compliance with the emissions cap.

    [Permit No. 0570039-070-AC; Application No. 0570039-084-AC; and Rule 62-4.070(3), F.A.C.]