FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

NORTHEAST DISTRICT
8800 BAYMEADOWS WAY WEST, SUITE 100
JACKSONVILLE, FLORIDA 32256

RICK SCOTT
GOVERNOR

HERSCHEL T. VINYARD JR.
SECRETARY

Sent by Electronic Mail – Received Receipt Requested

PERMITTEE

Renessenz, LLC
601 Crestwood St.
Jacksonville, Florida 32208

Authorized Representative:
Mr. Timothy Eberle, Sr. VP Operations

Air Permit No. 0310039-017-AC
Permit Expires: DRAFT
Issue date: DRAFT
Renessenz, LLC
Minor Source Air Construction Permit
Alternate Operation Mode/Boiler No. 1 Derating Trial Run of Processing Imported Raw Material Project

This is the final air construction permit, which authorizes an alternate mode of operation for the No. 6 column Crude Sulfate Turpentine sulfur removal; the derating of Boiler No. 1, the removal of the NOx CEMS, the trial run of processing imported raw material, and various miscellaneous other changes located at the Jacksonville Facility. The proposed work will be conducted at the Renessenz, LLC, which is a chemical manufacturing plant (Standard Industrial Classification No. 2869). The facility is located in Duval County at 601 Crestwood Street in Jacksonville, Florida. The UTM coordinates are Zone 17, 435.6 km East, and 3360.75 km North.

This final permit is organized by the following sections.

Section 1. General Information

Section 2. Administrative Requirements

Section 3. Emissions Unit Specific Conditions

Section 4. Prevention of Significant Deterioration Requirements

Section 5. 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.

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 Jacksonville, Florida

(DRAFT)

_____ _____

Richard S. Rachal III, P.G. (Date)
Program Administrator
Waste and Air Resource Management Program

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Permit package (including the Final Determination and Final Permit) 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 (DRAFT) to the persons listed below.

Brad James, P.E. (bjames@trinityconsultants.com)
Brian Zielinski, P.E., Renessenz, LLC (brian.zielinski@renessenz.com)
Timothy Eberle, Renessenz, LLC (tim.eberle@pinovaholdings.com)
Ana Oquendo, EPA Region IV, ana.oquendo@epa.gov
Natasha Hazziez, U.S. EPA Region 4: Hazziez.natasha@epa.gov)

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.

(DRAFT)

_____ _____

(Clerk) (Date)

FACILITY AND PROJECT DESCRIPTION

Existing Facility

This facility processes Crude Sulfate Turpentine, gum turpentine, and other chemicals to produce synthetic flavor and fragrance chemicals and also chemical intermediates. The facility operates one steam-generating boiler full time and two steam generating boilers as back-up units. The existing facility consists of the following emission units:

Facility ID No. 0310039	
ID No.	**Emission Unit Description**
-032	Boiler No. 1
-006	Boiler No. 6
-011	Boiler No. 7

Proposed Project

The applicant has applied for numerous changes to the facility which are described below:

(1) Boiler No. 1 Derating -- Renessenz has identified that the steam and process heat demands for the CST processing operations does not require the potential amount of steam and heat generated by Boiler No. 1. Engineering testing (SO2 emissions) of Boiler No. 1 was completed at an operation rate significantly above the normal steam needs for the facility (at a heat input rate of approximately 98 MMBtu/hr). Therefore, Renessenz is requesting to "derate" the current maximum heat input capacity to 99 MMBtu/hr for process steam needs at the Jacksonville facility. Upon completion of the derating process the boiler no. 1 shall be subject to 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This regulation does not require a CEMS for NOx because it does emission limit NOx emissions.

(2) C1/C2 Distillation Columns Bypass -- The first step required in CST processing is the removal of volatile sulfur compounds. At the Jacksonville facility, the initial fractionation is accomplished by distillation column T-1. The T-1 "lights" stream consists primarily of DMS and CST Lights, and the "product" stream is top sulfate turpentine (TST). Currently, the "lights" stream is processed in two (2) additional distillation columns (C1/C2) to separate DMS from the CST lights. The DMS is condensed and transported off-site while the CST lights are condensed and incorporated into the Glidfuel (Processed Derived Fuel [PDF]) mixture, which is used as a fuel in the boilers. Renessenz, LLC is proposing to route the T-1 "Lights" vapor stream directly to the boiler(s) for combustion of the vapor. The sulfur in the vapor stream is converted to sulfur dioxide during the combustion process. The proposed operation change will require no physical modifications to the existing boilers or distillation columns as well as ancillary process equipment at the facility. The operator can simply re-route the process vapors to the existing boilers via the movement of several process valves. Upon re-routing, instead of the process vapors being transferred to distillation column C1 for further processing, the process vapors will be transferred directly to one of the boilers for combustion.

(3) Simultaneous Operation of Boiler Nos. 1, 6, and 7 – Under Construction Permit No. 0310039-013-AC, Boiler Nos. 6 and 7 are limited to firing of natural gas under normal operating conditions and not allowed simultaneous operation with Boiler No. 1 except during transitional periods when Boiler No. 1 is starting up or shutting down. This specific condition also limits the fuel input of PDF to all of the

boilers and maximum annual use of PDF. Renessenz is requesting that this condition be removed from the permit to allow more operational flexibility of the Jacksonville facility.

This project will modify the following emissions unit(s):

Facility ID No. 0310039	
ID No.	**Emission Unit Description**
032	Boiler No. 1 fired by NG, ULSD No. 2 Fuel Oil, and Process Derived Fuel; or any combination of these fuels
006	Boiler No. 6 fired by NG, ULSD No. 2 Fuel Oil, and Process Derived Fuel; or any combination of these fuels
011	Boiler No. 7 fired by NG, ULSD No. 2 Fuel Oil, and Process Derived Fuel; or any combination of these fuels

FACILITY REGULATORY CLASSIFICATION

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility has no units subject to the acid rain provisions of the Clean Air Act (CAA).
- 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(PSD), F.A.C.

TRIAL RUN COLUMN C5

On August 29, 2013 the applicant applied for authorization to conduct a trial run of processing imported crude sulphate turpentine in the referenced column. Based upon the information received this trial run is approved subject to the following conditions:

a. Notify the Permitting Authority of the start-up date of the trial run a minimum of three days prior to commencing the trial run and an estimate of its duration. Notify the Permitting Authority of the completion of the trial run within seven days after completion.

b. Maximum amount of imported CST processed shall be limited to 100,000 gallons.

c. Process vapors generated by this trial run shall be captured and conveyed to one of the boilers for combustion.

d. Upon completion of the trial run submit a summary report of the trial and an estimate of the pollutant emissions generated from the trial. This report shall be submitted to the Permitting Authority within 90 days of completion.

SECTION 2. ADMINISTRATIVE REQUIREMENTS (DRAFT)

1. Permitting Authority: The permitting authority for this project is the Florida Department of Environmental Protection (Department), Northeast District Office, Waste and Air Resource Management Program. The Northeast District Office's mailing address is 8800 Baymeadows Way West, Suite 100, Jacksonville, Florida 32256. All documents related to applications for permits to operate an emissions unit shall be submitted to the Northeast District Office. The Permitting Authority's telephone number is 904-256-1700.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Florida Department of Environmental Protection (Department), Northeast District Office, Compliance Assurance. The mailing address and phone number of the Compliance Authority is: Florida Department of Environmental Protection (Department), Northeast District Office, Compliance Assurance, 8800 Baymeadows Way West, Suite 100, Jacksonville, Florida 32256. The Compliance Authority's telephone number is 904-256-1700.

3. Appendices: The following Appendices are attached as part of this permit:

   a. Appendix A. Citation Formats and Glossary of Common Terms;

   b. Appendix B. General Conditions;

   c. Appendix C. Common Conditions

   d. Appendix D. Common Testing Requirements

   e. Appendix E. 40 CFR 60, Subpart A, General Conditions

   f. Appendix BACT

   g. Appendix JEPB

   h. Appendix CEMS

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. Source Obligation:

   a. 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.

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 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.]

8. 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 unit. The permittee shall apply for a Title V air operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation of the project. 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, 62-4.220 and Chapter 62-213, F.A.C.]

9. Existing Permits and Regulations: The conditions of this permit supplements all other previously issued air construction and operation permits for these emissions units. These conditions are in addition to all other applicable permit conditions and regulatory requirements. The Permittee shall continue to comply with the conditions of those permits, which include restrictions and standards regarding capacities, production, operation, fuels, emissions, monitoring, recordkeeping, reporting, and the like.

A. Boiler No. 1

This section of the permit addresses the following emissions unit:

ID No.	Emission Unit Description
032	Boiler No. 1 fired by NG , ULSD, and PDF; or any combination of these fuels -- The Boiler is subject to Sulfur dioxide (SO_2), and opacity limitations in 40 CFR 60, Subpart Dc, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. The boiler is subject to notification and work practice standards in 40 CFR 63, Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants for Industrial-Commercial-Institutional Boilers Area Sources. The boiler is also subject to the particulate matter and SO2 standards in Rule 62-296.406, F.A.C. and Rule 2.1101, JEPB. The boiler is subject to the opacity standards in Rule 62-296.702, F.A.C. and Rule 2.1101, JEPB (Reasonably Available Control Technology requirements). Additional conditions have been added in Section 4 regarding Prevention of Significant Deterioration (PSD) and Operational Flexibility compliance determination.

EQUIPMENT

A.1. Equipment Name: Boiler No. 1 was originally designed with a maximum heat input of 180 MMBtu per hour (circa 1996) firing NG or No. 2 fuel oil. The boiler was retrofitted with a new low NOx burner and a variable forced draft fan resulting in a derated maximum heat input of 140 MMBtu per hour firing NG, ULSD, or PDF, or any combinations of these fuels. The permittee is authorized to again derate Boiler No. 1 to a maximum heat input rate of 99 MMBtu per hour by the installation of a new burner(s) which physically limits the maximum heat input rate.

[Permit No. 0310039-013-AC, and Application No. 0310039-017-AC]

PERFORMANCE RESTRICTIONS

A.2. Permitted Capacity: Boiler No. 1 shall be limited to a maximum heat input of 99 MMBtu per hour.

[Rule 62-210.200(PTE), F.A.C.; Limited by physical restrictions to the boiler, Applicant's Request]

A.3. Authorized Fuel: Fuels shall be limited to [1]NG, [1]ULSD, PDF, or any combination of these fuels. Vapors from the vapor collection system may also be incinerated in this emissions unit.

[[1]BACT Determination, Permit No. 0310039-013-AC, Application No. 0310039-017-AC and Rule 62-210.200(PTE), F.A.C.]

A.4. Operation: The hours of operation are not limited (i.e., 8760 hours per year).

[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

A.5. {Reserved}

A.6. Emission Limiting Standards for Opacity and Particulate Matter

a. Opacity

i. On and after the date on which the initial performance test is completed or is required to be completed under 40 CFR 60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, ULSD, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent

Condition A.6. Continued:

opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

ii. The opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

[40 CFR 60. 43c, Rule 62-204.800, F.A.C., and Rule 2.201, JEPB]

iii. The Boiler shall be subject to Visible Emissions – 20 percent opacity except for one six-minute period per hour during which opacity shall not exceed 27 percent.

[Rule 62-296.406(1), F.A.C.]

iv. The Boiler shall be subject to Visible Emissions – no greater than 20 percent opacity.

[Rule 62-296.702(2)(b), F.A.C. and Rule 2.1101, JEPB]

b. Particulate Matter

The Boiler is subject to a Best Available Control Technology Determination for particulate matter emissions. See attached BACT Determination.

[Rule 62-296.406(2), F.A.C.]

A.7. a. Emission Limiting Standards for SO_2 while burning ULSD or ULSD with other fuels:

On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

b. The fuel oil sulfur limits under this section apply at all times, including periods of startup, shutdown, and malfunction.

c. The Boiler shall be subject to a Best Available Control Technology Determination for sulfur dioxide emissions. BACT shall be the combustion of natural gas or ULSD oil with a maximum sulfur limit of 0.05% by weight.

[40 CFR 60. 42c(d), (h[1]), (i), Rule 62-204.800, F.A.C., Rule 62-296.406(3), F.A.C., and Rules 2.201and 2.1101, JEPB]

PERFORMANCE TEST METHODS FOR NITROGEN OXIDES SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.8. The permittee agrees to continue operation of the NOx CEMS for a minimum period of three months after demonstration of the maximum capacity of the derated Boiler No. 1. NOx CEMS data may be used in lieu of an annual stack test for NOx provided appropriate documentation of fuels is available for correlation with the recorded emission rate data.

[Rule 62-4.070, F.A.C. and Rule 2.2301, JEPB]

COMPLIANCE AND PERFORMANCE TEST METHODS FOR OPACITY, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.9. a. To determine compliance with the opacity limits under 40 CFR 60.43c, the owner or operator of an affected facility shall conduct an initial performance test as required under 40 CFR 60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

i. The owner or operator shall use data from the Continuous Opacity Monitoring System (COMS) to determine compliance in accordance with the procedures in 40 CFR 60.11(e)(5).

ii. Alternative test methods for visible emissions shall be EPA Reference Method No. 9 and the procedures in 40 CFR 60.11.

b. To determine compliance with the opacity limits under Rules 62-296. 406 and 62-296.702, F.A.C. and Rule 2.1101, JEPB the owner or operator of an affected facility shall conduct performance test each federal fiscal year, using the following procedures and reference methods:

i. The owner or operator shall use EPA Reference Method No. 9 for a minimum period of one hour.

ii. Alternative test methods for visible emissions shall be the use of data from the Continuous Opacity Monitoring System (COMS) to determine compliance

[40 CFR 60.46c, 40 CFR 60.11(e)(5), Rules 62-204.800, 62-296.406, and 62-296.702, F.A.C., Permit No. 0310039-013-AC, Rules 2.201 and 2.1101, JEPB, and Applicant's Request]

COMPLIANCE AND PERFORMANCE TEST METHODS FOR SULFUR DIOXIDE, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.10. a. For affected facilities subject to 40 CFR 60 60.42c(h)(1) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in 40 CFR 60.48c(f), as applicable.

Condition A.10. Continued:

b. For affected facilities subject to Rule 62-296.406(3), F.A.C. the owner or operator shall maintain compliance by only combusting fossil fuels as described Condition A.3.

[40 CFR 60.44c(h), Rule 62-204.800, F.A.C., and Rule 2.201, JEPB]

EMISSION MONITORING FOR NITROGEN OXIDES, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.11. Reserved

EMISSION MONITORING FOR OPACITY, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.12. a. The owner or operator of an affected facility subject to the opacity standard under 40 CFR 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

b. All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of Part 60. The span value of the opacity COMS shall be between 60 and 80 percent.

c. The operation of a continuous opacity monitoring system (COMS) as required by 40 CFR 60.47c(a) and (b), is applicable when this emissions unit combusts ULSD or mixtures of USLD with any other fuels.

[40 CFR 60. 47c(a and b), Rule 62-204.800, F.A.C., and Rule 2.201, JEPB]

EMISSION MONITORING FOR SULFUR DIOXIDE, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.13. The monitoring requirements of 40 CFR 60.46c(a) and (d) shall not apply to affected facilities subject to 40 CFR 60.42c(h)(1) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under 40 CFR 60.48c(f), as applicable.

[40 CFR 60.46c(e), Rule 62-204.800, F.A.C., and Rule 2.201, JEPB]

NOTIFICATION, RECORDKEEPING AND REPORTING REQUIREMENTS, SEE ADDITIONAL REQUIREMENTS IN SECTION 4 OF THE PERMIT

A.14. a. The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility (Boiler No. 1) and identification of the fuels to be combusted in the affected facility;

(2) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired.

b. The owner or operator of each affected facility subject to the SO_2 emission limits of 40 CFR 60.42c, or the PM or opacity limits of 40 CFR 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, performance evaluation of the CEMS and COMS using the applicable performance specifications in 40 CFR 60, Appendix B.

c. {Reserved}

d. The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

e. The owner or operator of each affected facility subject to the fuel oil sulfur limits under 40 CFR 60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(i) Calendar dates covered in the reporting period.

(ii) Each 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(iii) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f) below. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the [1]records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

[1] All fuel regulated by 40 CFR 60, Subpart Dc (i.e., distillate fuel oil)

f. Fuel supplier certification shall include the following information:

For distillate oil:

a. The name of the oil supplier;

b. A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in 40 CFR 60.41c; and

c. The sulfur content or maximum sulfur content of the oil.

Condition A.14. Continued:

g.(3) The owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in 40 CFR 60.42c to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

h. The owner or operator of any affected facility in any category listed in 40 CFR 60.7(f) is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in 40 CFR 60.43c(c) or to the operating parameter monitoring requirements in 40 CFR 60.13(i)(1).

(2) For the purpose of 40 CFR 60.43c, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under 40 CFR 60.43c(c).

i. The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period. Unless otherwise required by rule, order, or permit each 6 month period shall run as follows: JAN through JUN AND JUL through DEC.

j. A notification of the date construction of an affected facility (emission unit) is commenced postmarked no later than 30 days after such date.

k. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Department may request additional relevant information subsequent to this notice.

l. A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5). This notification shall be postmarked not less than 30 days prior to the date of the performance test.

m. Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

Condition A.14. Continued:

n. Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable 40 CFR 60 Subparts) and/or summary report form (see paragraph (d) of 40 CFR 60.7) to the Department semiannually, except when; more frequent reporting is specifically required by an applicable subpart; or the Department, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

o. The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Department. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Department.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

p. Reporting required more frequently than semi-annually may be reduced in accordance with the requirements of 40 CFR 60.7(e).

q. Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance

Condition A.14. Continued:

performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least five years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under 40 CFR 60.7(f), the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required under 40 CFR 60.7(f), if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

[40 CFR 60.7, 40 CFR 60. 48c, Rule 62-204.800, F.A.C., and Rule 2.201, JEPB]

B. Boiler No. 6

This section of the permit addresses the following emissions unit:

ID No.	Emission Unit Description
006	Boiler No. 6 fired by NG, ULSD, PDF, or any combinations of the fuels with a maximum design rate of 117.0 MMBtu per hour heat input. This emissions unit is subject to regulation under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with less than 250 Million Btu per hour Heat Input, New and Existing Sources. A Best Available Control Technology (BACT) determination is part of the review required by this rule – BACT Determination dated xx/xx/xxxx. The boiler is subject to notification and work practice standards in 40 CFR 63, Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants for Industrial-Commercial-Institutional Boilers Area Sources. The boiler is subject to the opacity standards in Rule 62-296.702, F.A.C. and Rule 2.1101, JEPB (Reasonably Available Control Technology requirements. The emission unit is also subject to the requirements of Jacksonville Environmental Protection Board Rules 2.301 – Stationary Sources General Requirements, 2.401 – Stationary Sources Preconstruction Review, 2.1001 – Stationary Sources Emission Standards, and 1.1101 – Stationary Sources Emission Monitoring. Additional conditions have been added in Section 4 regarding Prevention of Significant Deterioration (PSD) and Operational Flexibility compliance determination.

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

B.1. **Permitted Capacity.** The maximum heat input rate for this emissions unit shall not exceed 117.0 MMBtu/hr.

[Rule 62-210.200(PTE), F.A.C.; JEPB Rule 2.301, Construction Permit No. 0310039-009-AC]

OPERATING REQUIREMENTS

B.2. {Reserved}

B.3. **Methods of Operation**. This emissions unit may be fired with either NG, ULSD, PDF, or a blend of NG with PDF. At no time shall the firing of the fuels exceed the 117.0 MMBtu/hr heat input to the Boiler. Vapors from the vapor collection system may also be incinerated in this emissions unit.

Alternative Methods of Operation are described below:

Alternative Method	Fuel Options	Maximum Operating Rate
1	NG	117,009 CFH/hr
2	ULSD	830 Gal/hr
3	NG/PDF	---
4	PDF	1015.6

[Rules 62-4.160(2); 62-210.200(PTE), F.A.C.; Rule 62-213.410, F.A.C.; JEPB Rule 2.1301; JEPB Rule 2.301; JEPB Rule 2.501; Construction Permit No. 0310039-013-AC]

B.4. Hours of Operation. The hours of operation of Boiler No. 6 shall not be limited. The hours of operation shall be recorded.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; JEPB Rule 2.1301; JEPB Rule 2.301; Construction Permit No. 0310039-013-AC]

Emission Limitations and Performance Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.5. Particulate Matter Emissions. Particulate Matter (PM) Emissions shall be limited by the firing of the fuels stated in **Condition B.3.**

[BACT Determination dated November 5, 2003, Rule 62-212.300, F.A.C.]

B.6. Sulfur Dioxide Emissions. Sulfur Dioxide Emissions shall be limited to the sulfur content in the fuels stated in **Condition B.7.** and no more than 850 TPY.

{Permitting Note: Emission Cap established during County/State petition for SO_2 redesignation, SO_2 includes emissions generated by combusting process vapors}

[Rule 62-296.406(3), F.A.C.; JEPB Rule 2.1001; BACT Determination dated November 5, 2003; Operation Permit No. AO16-169132; Construction Permit No. 0310039-013-AC]

B.7. Sulfur Content – Fuels. The maximum sulfur content of the fuels allowed to be fired in this emissions unit are listed below and shall not be exceeded:

Fuel Type	***Maximum Sulfur Content***
NG	-----
ULSD	0.05 wt. %
PDF	0.5 wt%

[BACT Determination dated 11/05/03; JEPB Rule 2.1001; Construction Permit No. 0310039-013-AC]

B.8. Visible Emissions.

a. Visible Emissions shall not exceed 20% Opacity, except for one six-minute period per hour during which opacity shall not exceed 27 percent.

[Rule 62-296.406(1),F.A.C.; JEPB Rule 2.1001; Construction Permit No. 0310039-013-AC]

b. Visible Emissions shall not exceed 20% Opacity

[Rule 62-296.702, F.A.C. and JEPB Rule 2.1101]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.9. Compliance Testing- Sulfur Dioxide. In lieu of an annual compliance stack test for sulfur dioxide emissions, the Permittee shall comply with the fuel sulfur content restrictions stated in **Condition No. B.7.**

The permittee shall conduct sulfur dioxide compliance test using EPA Method 6, upon Department request in accordance with the requirements of **Condition No. B.14**.

[Construction Permit No. 0310039-009-AC]

B.10. Compliance Testing- Particulate Matter Emissions shall be limited by the firing of the fuels stated in **Condition B.3. A**lso see Section 4.

[0310039-013-AC]

B.11. Compliance Testing- Visible Emissions. The test method for visible emissions for this emissions unit shall be EPA Method 9 as stated in Rule 62-297.401(9)(c) F.A.C. This compliance test shall be conducted each federal fiscal year.

[Rule 62-297.401(9)(c) F.A.C., JEPB Rule 2.1101]

B.12. Sulfur Content. The permittee shall comply with the following:

- Each delivery of ULSD to be fired in the No. 6 Boiler shall be analyzed for the sulfur content prior to use. If ULSD is added to the tank a new analysis is required. Fuel oil supplier analysis may be substituted for the testing provided the analysis is conducted in accordance with established and appropriate ASTM methods listed below. Alternate testing methods shall be submitted to the Permitting Authority for approval prior to implementing.

- Each batch of the PDF used in the No. 6 Boiler shall be analyzed for its sulfur content. The sulfur content in the PDF fired shall be determined by the latest sampling and analytical procedures specified in ASTM D-129 or ASTM D-2622 procedures. The laboratory shall certify results. Alternate testing methods shall be submitted to the Permitting Authority for approval prior to implementing.

[Construction Permit No. 0310039-013-AC]

B.13. SO_2 Recordkeeping. The Permittee shall maintain a record of the fuel oil sulfur content analysis results stated in **Condition No. B.13.** for a period of 5 years.

[Rule 213.440(1)b., F.A.C., JEPB Rule 2.501; Construction Permit No. 0310039-013-AC]

Common Conditions - F.A.C. Test Requirements

B.14. This emissions unit is also subject to Prevention of Significant Deterioration Requirements in Section 4 and applicable F.A.C. Test Requirements in Section 5.

C. Boiler No. 7

This section of the permit addresses the following emissions unit:

ID No.	Emission Unit Description
011	Boiler No. 7 fired by NG, Ultra Low Sulfur Distillate fuel oil, process derived fuel, or any combinations of the fuels with a maximum design rate of 49.0 MMBtu per hour heat input. This emissions unit is subject to regulation under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with less than 250 Million Btu per hour Heat Input, New and Existing Sources. A Best Available Control Technology (BACT) determination is part of the review required by this rule – BACT Determination dated xx/xx/xxxx. The boiler is subject to notification and work practice standards in 40 CFR 63, Subpart JJJJJJ, National Emission Standards for Hazardous Air Pollutants for Industrial-Commercial-Institutional Boilers Area Sources. The boiler is subject to the opacity standards in Rule 62-296.702, F.A.C. and Rule 2.1101, JEPB (Reasonably Available Control Technology requirements. The emission unit is also subject to the requirements of Jacksonville Environmental Protection Board Rules 2.301 – Stationary Sources General Requirements, 2.401 – Stationary Sources Preconstruction Review, 2.1001 – Stationary Sources Emission Standards, and 1.1101 – Stationary Sources Emission Monitoring. Additional conditions have been added in Section 4 regarding Prevention of Significant Deterioration (PSD) and Operational Flexibility compliance determination.

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

C.1. **Permitted Capacity.** The maximum heat input rate for this emissions unit shall not exceed 49.0 MMBtu/hr.

[Rule 62-210.200(PTE), F.A.C.; JEPB Rule 2.301, Construction Permit No. 0310039-013-AC]

OPERATING REQUIREMENTS

C.2. **Methods of Operation**. This emissions unit may be fired with either NG, ULSD, PDF, or a blend of NG with PDF. At no time shall the firing of the fuels exceed the 49.0 MMBtu/hr heat input to the Boiler. Vapors from the vapor collection system may also be incinerated in this emissions unit.

Alternative Methods of Operation are described below:

Alternative Method	Fuel Options	Maximum Operating Rate
1	NG	46,800 CF/Hr
2	ULSD	348 Gal/hr
3	NG/PDF	---
4	PDF	425 Gal/hr

[Rules 62-4.160(2); 62-210.200(PTE), F.A.C.; Rule 62-213.410, F.A.C.; JEPB Rule 2.1301; JEPB Rule 2.301; JEPB Rule 2.501; Construction Permit No. 0310039-009-AC]

C.3. Hours of Operation. The hours of operation shall not be limited. The hours of operation shall be recorded.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; JEPB Rule 2.1301; JEPB Rule 2.301; Construction Permit No. 0310039-013-AC]

Emission Limitations and Performance Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.4. Particulate Matter Emissions. Particulate Matter (PM) Emissions shall be limited by the firing of the fuels stated in **Condition C.2.**

[BACT Determination dated November 5, 2003, Rule 62-212.300, F.A.C.]

C.5. Sulfur Dioxide Emissions. Sulfur Dioxide Emissions shall be limited to the sulfur content in the fuels stated in **Condition C.6.** and no more than 139.3 TPY.

{Permitting Note: Emission Cap established during County/State petition for SO_2 redesignation}

[Rule 62-296.406(3), F.A.C.; JEPB Rule 2.1001; BACT Determination dated November 5, 2003; Operation Permit No. AO16-169132; Construction Permit No. 0310039-009-AC]

C.6. Sulfur Content – Fuels. The maximum sulfur content of the fuels allowed to be fired in this emissions unit are listed below and shall not be exceeded:

A. Fuel Type	***B. Maximum Sulfur Content***
NG	-----
ULSD	0.05 wt. %
PDF	0.5 wt%

[BACT Determination dated 11/05/03; JEPB Rule 2.1001; Construction Permit No. 0310039-009-AC]

C.7. Visible Emissions.

a. Visible Emissions shall not exceed 20% Opacity, except for one six-minute period per hour during which opacity shall not exceed 27 percent.

[Rule 62-296.406(1),F.A.C.; JEPB Rule 2.1001; Construction Permit No. 0310039-013-AC]

b. Visible Emissions shall not exceed 20% Opacity

[Rule 62-296.702, F.A.C. and JEPB Rule 2.1101]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.8. Compliance Testing- Sulfur Dioxide. In lieu of an annual compliance stack test for sulfur dioxide emissions, the Permittee shall comply with the fuel sulfur content restrictions stated in **Condition No. C.6.**

The permittee shall conduct sulfur dioxide compliance testing using EPA Method 6, upon Department request, in accordance with the requirements of **Condition No. C.13**.

[Construction Permit No. 0310039-013-AC]

C.9. Compliance Testing- Particulate Matter Emissions shall be limited by the firing of the fuels stated in **Condition C.2.**

[Construction Permit No. 031009-013-AC]

C.10. Compliance Testing- Visible Emissions. The test method for visible emissions for this emissions unit shall be EPA Method 9 as stated in Rule 62-297.401(9)(c) F.A.C. This compliance test shall be conducted each federal fiscal year.

[Rule 62-297.401(9)(c) F.A.C., JEPB Rule 2.1101]

C.11. Sulfur Content. The permittee shall comply with the following:

- Each delivery of ULSD to be fired in the No. 7 Boiler shall be analyzed for the sulfur content prior to use. If ULSD is added to the tank a new analysis is required. Fuel oil supplier analysis may be substituted for the testing provided the analysis is conducted in accordance with established and appropriate ASTM methods listed below. Alternate testing methods shall be submitted to the Permitting Authority for approval prior to implementing.

- Each batch of the PDF used in the No. 7 Boiler shall be analyzed for its sulfur content. The sulfur content in the PDF fired shall be determined by the latest sampling and analytical procedures specified in ASTM D-129 or ASTM D-2622 procedures. The laboratory shall certify results. Alternate testing methods shall be submitted to the Permitting Authority for approval prior to implementing.

[Construction Permit No. 0310039-013-AC]

C12. SO_2 Recordkeeping. The Permittee shall maintain a record of the fuel oil sulfur content analysis results stated in **Condition No. C.11.** for a period of 5 years.

[Rule 213.440(1)b., F.A.C., JEPB Rule 2.501; Construction Permit No. 0310039-013-AC]

Common Conditions - F.A.C. Test Requirements

C.13. This emissions unit is also subject to Prevention of Significant Deterioration Requirements in Section 4 and applicable F.A.C. Test Requirements in Section 5.

RECORDKEEPING AND REPORTING REQUIREMENTS

D.1. Actual Emissions Reporting: This permit is based on an analysis that compared baseline actual emissions with projected actual emissions and the project 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.

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 years following resumption of regular operations after the change. 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 as calculated 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 provide by Appendix C of this permit. For this project, the permittee shall use the following methods in reporting the actual annual emissions for the Project 0310039-017-AC (identified as Emission Unit Nos. 032, 006, and 011):

1) Emission Unit No. 032 (Boiler No. 1)

i. The permittee shall use the procedures listed below to determine and report the actual annual emissions of NO_X for the No. 1 Boiler. NOx CEMS data may be used in lieu of an annual stack test for NOx as specified within Condition A.8.

ii. The permittee shall use the data collected from the required stack tests to verify the EF used to calculate actual annual emissions of PM/PM_{10}. The permittee shall follow the stack test methods, test procedures and test frequencies specified in this permit. To determine compliance, the test results must be at or below the PM EF listed in the Performance Restrictions section of the permit. To calculate the annual PM emissions, the activity factor for the calendar year shall be multiplied by the EF to determine the

Condition D.1. Continued:

annual emissions.

iii. The permittee shall use stoichiometric data calculations to determine SO_2 emissions. Total pounds of sulfur received by the facility during the reporting period shall be the basis for determining the annual SO_2 emissions. Sulfur which may be adequately accounted that is not combusted may be deducted from the total sulfur used for the calculations.

iv. Unless otherwise approved by the Department, the permittee shall use the same emissions factors for reporting the actual annual emissions of CO and VOC as used in the application to establish baseline emissions multiplied by the calendar year activity factor.

2) Emission Unit Nos. 006 and 011 (Boiler Nos. 6 and 7 respectively)

i. The permittee shall follow the stack test methods, test procedures and test frequencies specified in this permit. To determine compliance, the test results must be at or below the PM EF listed in the Performance Restrictions section of the permit. To calculate the annual PM emissions the activity factor for the month shall be multiplied by the Performance Restriction limit to determine the emissions.

ii. The permittee shall use stoichiometric data calculations to determine SO_2 emissions. Total pounds of sulfur received by the facility during the reporting period shall be the basis for determining the annual SO_2 emissions. Sulfur which may be adequately accounted, that is not combusted, may be deducted from the total sulfur used for the calculations.

iii. Unless otherwise approved by the Department, the permittee shall use the same emissions factors for reporting the actual annual emissions of CO and VOC as used in the application to establish baseline emissions multiplied by the calendar year activity factor.

iv. The emission factors listed in the Performance Restrictions shall be used to calculate the annual NOx emissions from the operation of Boiler Nos. 6 and 7. The emission factor shall be multiplied times the activity factor for each fuel fired in the Boiler(s) for the calendar year. To determine compliance, the test results must be at or below the NOx EF listed in the Performance Restrictions section of the permit.

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

[Application No. 0310039-013-AC; Rules 62-212.300(1)(e), and 62-210.370, F.A.C.]

D.2. Recordkeeping: The permittee shall maintain records as follows:

a. The quantity and sulfur content by weight of each shipment received of crude sulphate turpentine. These records shall be provided to the Department upon request.

Condition D.2. Continued:

b. Calculations on a monthly basis of sulfur dioxide emissions based upon the methodology listed in Section 4, Recordkeeping and Reporting Requirements, D.1.,d,1), iii. above.

c. Records of each fuel burned in each Boiler as follows:

1) Quantity and number of hours on a monthly basis

2) Analysis as follows:

i. *Fuel oil for each shipment received for sulfur percent by weight

ii. Process derived fuel (PDF) for each batch produced for sulfur percent by weight

* Fuel oil supplier records may be used provided analytical methods are identified and are acceptable to the Department.

TESTING AND ANALYSIS REQUIREMENTS

D.3. Stack Testing (Boiler No. 1). Record the quantity and type of each fuel fired during each test.

a. PM on an annual basis (each calendar year) using EPA RM 5 while firing PDF. PM on an annual basis (each calendar year) using EPA RM 5 while firing fuel oil (if fuel oil was combusted during the previous 12 months other than for standby purposes).

b. SO_2, upon request, using EPA RM 6 or other method approved by the Department

c. Oxides of Nitrogen (NOx) while firing PDF shall be conducted on an annual basis using EPA RM 7 or 7E. NOx while firing NG shall be conducted on an annual basis using EPA RM 7 or 7E. NOx while firing fuel oil (if fuel oil was combusted during the previous 12 months other than for standby purposes) shall be conducted on an annual basis using EPA RM 7 or 7E.

d. CO, upon request, using EPA RM 10 or other method approved by the Department

e. VOC, upon request, using EPA RM 25 or other method approved by the Department

D.4. Stack Testing (Boiler No. 6). Record the quantity and type of each fuel fired during the test.

a. PM on an annual basis (each calendar year) using EPA RM 5 while firing PDF. PM on an annual basis (each calendar year) using EPA RM 5 while firing fuel oil (if fuel oil was combusted during the previous 12 months other than for standby purposes). Testing is for the purpose of insuring that emissions of PM are equal to or less than the Emission Factor in condition A.9.

b. SO_2, upon request, using EPA RM 6 or other method approved by the Department

c. Oxides of Nitrogen (NOx) while firing PDF (if PDF was combusted during the previous 12 months) shall be conducted on an annual basis using EPA RM 7 or 7E. NOx while firing NG shall be conducted on an annual basis using EPA RM 7 or 7E. NOx while firing fuel oil (if fuel oil was combusted during the previous 12 months other than for standby purposes) shall be

Condition D.4. Continued:

conducted on an annual basis using EPA RM 7 or 7E. Testing is for the purpose of insuring that emissions of NOx are equal to or less than the Emission Factor in condition A.9.

d. CO, upon request, using EPA RM 10 or other method approved by the Department

e. VOC, upon request, using EPA RM 25 or other method approved by the Department

D.5. Each batch of PDF produced shall be analyzed for the sulfur content (% by weight). Applicable ASTM Methods shall be used as approved in 40 CFR 60. 17. Alternate methods may be approved in writing by the Department.

*Fuel oil and NG fuel supplier records may be used provided analytical methods are identified and are acceptable to the Department.

[Rules 62-212.300(1)(e), 62-210.370, and 62-4.070, F.A.C.]

PERFORMANCE RESTRICTIONS AND REQUIREMENTS

D.6. The permittee shall measure the fuel flow rates to each boiler. The fuel flow measurement device(s) shall be accurate to within plus or minus 5 percent accuracy. Calibration of the device(s) shall be conducted in accordance with manufacturers' instructions on a frequency recommended by the manufacturer. Monthly records of the fuel flow shall be compiled and maintained and made available to the Department upon request.

D.7. In no case shall Boiler Nos. 6/7 total combust in excess of 3.285 million gallons of PDF per 12 month rolling total or an equivalent combination (measured as Btu input) of PDF and NG. Boiler Nos. 6/7 total shall not exceed an average firing rate (combined) of 123 million Btu per hour during the operational period.

D.8. A mass emission reduction (from fuel combustion of natural gas, ultra low sulfur fuel oil, and processed derived fuel) is expected from Boiler No. 1 since it will be derated to a maximum heat input capacity of 99 MMBtu per hour. In order to provide operational flexibility to the facility simultaneous operation of Boiler Nos. 1, 6 and 7 shall be allowed subject to the following emission based conditions to insure continued compliance with previous permitted requirements in lieu of CEM(s) monitoring:

12 Month Rolling Total

EF = Emission Factor

AF = Activity Factor

Emission Factor

Pollutant	Boiler No. 1	Boiler No. 6	Boiler No. 7
NOx (PDF)	0.20 lb/MMBtu	0.289 lb/MMBtu	0.289 lb/MMBtu
NOx (NG)	0.20 lb/MMBtu	0.265 lb/MMBtu	0.265 lb/MMBtu
NOx (Fuel Oil)	0.20 lb/MMBtu	0.171 lb/MMBtu	0.171 lb/MMBtu
*PM (PDF)	0.131 lb/MMBtu	0.131 lb/MMBtu	0.131 lb/MMBtu
*PM (Fuel Oil)	0.171 lb/MMBtu	0.171 lb/MMBtu	0.171 lb/MMBtu
*PM (NG)	Negligible	Negligible	Negligible

*PM_{10} and $PM_{2.5}$ are equal to PM emissions

Activity Factor

MMBtu per month per fuel type per boiler

12 Month Rolling Total, Compliance Calculation Method

Each month the total lbs of each pollutant per boiler shall be calculated by multiplying the appropriate EF times the AF for each fuel type in each boiler. Each month's total lbs emitted shall be added to the previous 11 months total to determine the 12 month rolling total emission of each pollutant. Compliance for each pollutant (12 month rolling total) shall be demonstrated if the sum (total) emissions from all three boilers is equal to or less than the following maximum 12 month rolling total emissions:

**NOx -- 245,280 lbs per 12 month rolling total maximum

**$PM/PM_{10}/PM_{2.5}$ -- 186,314 lbs per 12 month rolling total maximum

**Equal to potential to emit from Boiler No. 1 at a rated capacity of 140 MMBtu per hour

[PSD Avoidance]