Breitburn Operating LP

St. Regis Gas Treating Facility and Jay Gas Plant

Facility ID No. 1130005
Santa Rosa County

Title V Air Operation Permit Revision

Permit No.: 1130005-019-AV
Revision to Title V Air Operation Permit No.: 1130005-012-AV

<u>Permitting and Compliance Authority:</u>

State of Florida
Department of Environmental Protection
Northwest District

160 W. Government Street, Suite 308
Pensacola, Florida 32502-5740

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March 9, 2105

Title V Air Operation Permit Revision

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Referenced attachments made a part of this permit:

Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX SS-1, STACK SAMPLING FACILITIES version dated 10/07/96
APPENDIX TV-6, TITLE V CONDITIONS version dated 06/23/06
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix 40 CFR 60 A
Appendix 40 CFR 60 GG
Appendix 40 CFR 60 VVa
Appendix 40 CFR 60 OOOO
Appendix 40 CFR 63 A
Appendix 40 CFR 63 HH
Appendix 40 CFR 63 ZZZZ
Appendix 40 CFR 63 DDDDD
Attachment 1, EPA Approved Custom Fuel Sample Schedule
Attachment-2, Sulfur Pit Approval Letter

The following appendices are not enforceable parts of this permit and are included for reference purpose only.

Appendix H, Permit History
Appendix TSAC, Time Sensitive Action Chart

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

NORTHWEST DISTRICT
160 W. GOVERNMENT STREET
PENSACOLA, FLORIDA 32502-5794

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March 9, 2015

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Breitburn Operating LP
5 Houston Center
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Permit No.: 1130005-019-AV
Facility ID No.: 1130005
SIC No(s).: 13, 1311, 1321
Project: Title V Air Operation Permit

This permit revision is being issued for the purpose of incorporating the terms and conditions of air construction Permit No. 1130005-018-AC and to clarify natural gas language established in Title V Air Operation Permit No. 1130005-012-AV. This facility is located in Santa Rosa County at 5415 Oil Plant Road, Jay Florida; UTM Coordinates: Zone 17, 482.8 km East and 3425.6 km North; and, Latitude: 30° 52' 45" North and Longitude: 87° 10' 45" West.

This Title V Air Operation Permit Revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210 and 62-213. The above named permittee is hereby authorized to operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Initial Effective Date: January 17, 2011
Revision Effective Date: March 9, 2015
Renewal Application Due Date: June 6, 2015
Expiration Date: January 17, 2016

_____**/s/**_____
Elizabeth Mullins Orr
Permitting Program Administrator
Northwest District

EMO/aj/m

Section I. Facility Information.

This is a revision to Title V renewal permit 1130005-012-AV, effective January 17, 2011, to incorporate permit 1130005-018-AC for the removal of the natural gas throughput limits for the Glycol Reboiler Vent (Emissions Unit 048) and the Natural Gas Liquids Fractionation Unit (Emissions Unit 052).

The Tri-Ethylene Glycol (TEG) Dehydration Unit removes water from wet natural gas from the field. The wet gas is run through an absorber column where the TEG absorbs the water from the natural gas. A Glycol Reboiler is used to remove the water from the TEG so it may be recycled through the process. The Glycol Reboiler used to vent only through a condenser to control VOC and HAPs emissions. The natural gas flow rate was a vital part of calculating emissions using the GRI-GLYCalc computer program and the natural gas flow rate limit was established based on the capabilities of the condenser control system. The facility chose in 2003 to demonstrate compliance with the Maximum Achievable Control Technology (MACT) Standard for Oil and Natural Gas Production by installing a venturi burner in the reboiler section of the Tri-Ethylene Glycol Dehydration Unit to combust the gases from the glycol reboiler condenser vent. The emissions that occur now from the Tri-Ethylene Glycol Dehydration Unit are mostly the fugitive emissions from components (valves, pumps flanges and pressure relief valves, etc.). Emissions are thus not based now on process flow rates but are calculated based on emissions factors, types, and number of components. A change in inlet gas flow throughput does not result in changes to the calculated emissions rates. The process rate limit of 90 MMscf per day is no longer applicable.

Natural gas coming directly from a well contains many natural gas liquids, including ethane, propane, butane, iso-butane, and natural gasoline. There are two basic steps to the treatment of natural gas liquids in natural gas. First, the liquids must be extracted from the natural gas. Second, these natural gas liquids must be separated (fractionated) down to their base components. These natural gas liquids are composed mainly of hydrocarbons containing one to eight carbon atoms per molecule. The separation of the hydrocarbon mixtures is performed by fractional distillation in column distillers in the Natural Gas Fractionation Unit. The Natural Gas Fractionation Unit is a closed-vent system. Any gases left over after the products (propane, stable gasoline, butane, and isobutene) are extracted are re-introduced into the well field to help keep the field pressure. The only emissions that occur are limited to the fugitive emissions from components (valves, pumps flanges and pressure relief valves, etc.). Emissions are not based on process flow rates but are calculated based on emissions factors, types, and number of components. A change in inlet gas flow throughput does not result in changes to the calculated emissions rates. The limit of the process rate of 90 MMscf per day to the Natural Gas Fractionation Unit was originally imposed to be consistent with the same limitation that has existed for years for the Tri-Ethylene Glycol Dehydration Unit. This limit is not applicable and is thus being removed.

Subsection A. Facility Description.

This facility consists of sulfur recovery plants, oil and gas treating including natural gas dehydration and tri-ethylene glycol (TEG) regeneration, saltwater disposal, and tertiary recovery.

Two Sulfur Recovery Plants (J2 and J3) (EU 034), were built in the early 1970s and precede NSPS requirements but are subject to emission limits in Rule 62-296.409(2), F.A.C. These plants control sulfur emissions from the production and treating of sour crude oil and gas from the Jay Oil Field. Acid gas containing H_2S from oil and gas production is oxidized and reacted to form elemental sulfur by a multi stage Claus process. A minimum of 96% of the H_2S is recovered as elemental sulfur. Unconverted H_2S is thermally oxidized to SO_2 prior to discharge.

The Primary Emergency Flare (FL01) and the Saltwater Disposal System Flare (FL02) (EU 035) were built in the early 1980s. The primary emergency flare includes continuous feed and purge streams with a 26.0 M cubic feet per hour pilot; and the JCSWD system flare, continuous feed streams and a 0.5 M cubic feet per hour pilot stream. SO_2 emissions, limited by Initial Title V Operation permit 1130005-001-AV, are controlled by a smokeless flare tip on each flare with a manual eductor gas system.

A Centaur turbine (EU 037) located at the Jay Central Saltwater Disposal Facility (JCSWD) was constructed in 1983. The natural gas fired turbine is subject to 40 CFR 60 Subpart GG - Stationary Gas Turbines, and 40 CFR 63 Subpart YYYY - Stationary Combustion Turbines, incorporated by reference in Rule 62-204.800(8)(b)41 and 62-204.800(11)(b)81, F.A.C., respectively. In addition this unit is subject to applicable requirements of both 40 CFR 60 and 63 Subpart A - General Provisions.

A 1,000 HP Recompressor 4-stroke rich-burn Engine (EU 038) and five 1,000 HP Ingersoll-Rand Recompressor Engines (EU 044) each with a heat input of 11.6 MMBtu per hour are all equipped with catalytic converters. The catalytic converters limit the exhaust concentration of formaldehyde, to comply with 40 CFR 63 Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines. Sulfur Storage Pits (Jay 2 and Jay 3) (EU 039) are used to store molten sulfur. Loading racks transfer the molten sulfur to tanker trucks.

The Glycol Reboiler Condenser Vent (EU 048) controlled HAP and VOC emissions with an air-cooled condenser. Wet natural gas and dry tri-ethylene glycol (TEG) are contacted in a packed contactor tower to remove water from the natural gas. The TEG is regenerated by heating and vaporizing the water content as steam in the TEG reboiler. Dried TEG is reused in the contactor tower, while the vapor is condensed to recover organics. 40 CFR 63 Subpart HH - Oil and Natural Gas Production Facilities, regulates this process, a major source of HAP. The condenser vent stream is now combusted in the flame-zone of the TEG reboiler process heater with a venturi burner. This allows Breitburn (formerly known as Quantum) to be exempt from preparing a design analysis, and conducting performance testing and monitoring.

Various gas fired Process Heaters (Jay 2 and Jay 3 process heater, Jay 2 and Jay 3 stabilizer bottom heaters and Jay plant hot oil heater) (EU 040, 041 and 042) are used throughout the facility and are subject to 40 CFR 63 Subpart DDDDD. The two natural gas-fired Cooper-Bessemer Engines (EU 045 and 046) are existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP. These engines do not have to meet the requirements of 40 CFR 63 Subpart ZZZZ, including initial notification requirements, in accordance with 40 CFR 63.6590(b)(3)(i.).

A natural gas-fired Water Flood Turbine (EU 050) is regulated by Rule 62-296.320, F.A.C., and is not subject to 40 CFR 60 Subpart GG, 40 CFR 60 Subpart KKKK, and 40 CFR 63 Subpart YYYY.

A skid-mounted Natural Gas Liquids Fractionation Unit (EU 052) fractionates natural gas liquids (NGLs) produced from the Jay Oil Field DE-C2 Tower into propane, butane and natural gasoline. Natural gas coming directly from a well contains many NGLs that are commonly removed. NGLs include ethane, propane, butane, iso-butane, and natural gasoline. There are two basic steps to the treatment of NGLs in the natural gas stream. First, the liquids must be extracted from the natural gas. Second, these NGLs must be separated themselves, down to their base components. The skid-mounted Natural Gas Liquids Fractionation Unit consists of a depropanizer, a debutanizer, accumulators (propane and debutanizer), condensers (propane and butane), reboilers (depropanizer and debutanizer), pumps (depropanizer reflux and debutanizer reflux) and an R-G cooler. A molecular sieve helps purify gas going to the fractionation unit by removing sulfur compounds.

Propane and butane not meeting sales specifications are recycled by use of an off-spec pressurized gas vessel. Natural gas from the Natural Gas Liquids Fractionation Unit is returned to the field to aid in further oil recovery. Propane, butane and natural gasoline are temporarily stored on-site for off-site sales. The natural gasoline produced is sent to two existing 630,000 gallon crude oil storage tanks to be mixed with processed crude.

The Jay Plant Hot Oil Heater (EU 042) supplies heat to the Natural Gas Liquids Fractionation Unit.

An unregulated emissions unit (EU 047) consisting of two 630,000 gallon fixed roof processed crude oil storage tanks are used by the fractionation unit, increasing the throughput to the storage tanks to approximately 69,300,000 gallons per year combined. These tanks were constructed in the early 1970's and pre-date NSPS requirements.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the Title V Air Operation Permit Revision application received August 7, 2014, this facility is a major source of hazardous air pollutants (HAP).

The Breitburn Operating LP St. Regis Gas Treatment Facility and Jay Gas Plant is considered a major stationary source for Prevention of Significant Deterioration (PSD). The facility belongs to one of the 28 PSD-major facility categories as a Sulfur Recovery Plant and its potential emissions of VOC, SO_2, NO_X and CO are greater than 100 tons per year. Any future modifications and/or construction must be evaluated with respect to the preconstruction review requirements of Rule 62-212.300(1) - (3), F.A.C.

Subsection B. Summary of Emissions Unit ID Nos. and Brief Descriptions

EU I.D.	Brief Description
034	Sulfur Recovery Plants J2 and J3
035	Flares FL01 and FL02
037	JCSWD Solar Centaur Turbine Subject to 40 CFR 60 Subpart GG
038	Recompressor Engine with Catalytic Converter
039	Sulfur Pits
048	TEG Reboiler subject to 40 CFR 63 Subpart HH
040	Jay 2 and 3 Process Heaters - 56.7 MMBtu per hour each heater
041	Jay 2 and 3 Stabilizer Bottom Heaters - 28.4 MMBtu per hour each heater
042	Jay Plant Hot Oil Heater - 55.65 MMBtu per hour
044	Five 1,000 HP natural gas fired Ingersol Rand Compressor Engines with Catalytic Converters - 11.6 MMBtu per hour heat input
045	(1) - 5,000 HP natural gas fired Cooper-Bessemer "A" Engine - 42.0 MMBtu per hour heat input with "Clean Burn" Combustion Technology
046	(1) - 2,500 HP natural gas fired Cooper-Bessemer "B" Engine - 21.0 MMBtu per hour heat input
042	Jay Plant Hot Oil Heater - 55.65 MMBtu per hour heat input
052	Natural Gas Liquids Fractionation Unit - skid mounted

Unregulated Emissions Units and/or Activities

043	14,300 HP (North) Water Flood Gas Turbine
047	(2) - 630,000 gallon fixed roof processed crude oil Storage Tanks
049	Fugitive Emissions

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

These documents are provided to the permittee for information purposes only:
Appendix A-1: Abbreviations, Acronyms, Citations, and Identification Numbers
Statement of Basis

These documents are on file with the permitting authority:
Application for a Title V Air Operation Permit Revision received August 7, 2014
Additional Information Request dated August 15, 2014
Additional Information Response received November 18, 2014

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. Appendices. The permittee shall comply with all documents identified in Section IV Appendices, listed in the Table of Contents as referenced attachments made a part of this permit. Each document is an enforceable part of this permit unless otherwise indicated. [Rule 62-213.440, F.A.C.]

2. [Not federally enforceable.] General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C. [Rules 62-296.320(4)(b)1. & 4., F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA). If and when the facility becomes subject to 112(r), the permittee shall:

a. Submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent electronically through EPA's Central Data Exchange system at the following address: https://cdx.epa.gov. Information on electronically submitting risk management plans using the Central Data Exchange system is available at: http://www.epa.gov/osweroe1/content/rmp/index.htm. The RMP Reporting Center can be contacted at: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038, Telephone: (703) 227-7650.
b. Submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.

[40 CFR 68]

{Permitting Note: The Facility is not subject to this requirement at the time of this permit}

5. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. . To comply, procedures to minimize pollutant emissions shall include the following:

a. Tightly cover or close all VOC containers when they are not in use.
b. Tightly cover, where possible, all open troughs, basins, baths, tanks, etc., when they are not in use.
c. Maintain all piping, valves, fittings, etc., in good operating condition.
d. Prevent excessive air turbulence across exposed VOC.
e. Immediately confine and clean up VOC spills and make sure appropriate wastes are placed in closed containers for reuse, recycling or proper disposal.

[Rule 62-296.320(1)(a), F.A.C.]

6. Emissions of Unconfined Particulate Matter: Pursuant to Rules 62-296.320(4)(c)1, 3 & 4, F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following requirements outlined in the attached, "Precautions to Prevent Emissions of Unconfined Particulate Matter" and incorporated into this permit. (See Condition 57 of APPENDIX TV-6, TITLE V CONDITIONS):
The following requirements are included in this permit:

a. Trucks and vehicles shall stay on paved perimeter roads whenever possible to move from one location to another.
b. Vegetation and gravel shall be used to prevent wind generated dust associated with open spaces within the facility.
c. Walkways and paths within the facility shall be paved to minimize dust generated by personnel traffic.

[Rule 62-296.320(4)(c)2, F.A.C.]

7. Electronic Annual Operating Report and Title V Annual Emissions Fees. The information required by the Annual Operating Report for Air Pollutant Emitting Facility [Including Title V Source Emissions Fee Calculation] (DEP Form No. 62-210.900(5)) shall be submitted by April 1 of each year, for the previous calendar year, to the Department of Environmental Protection's Division of Air Resource Management. Each Title V source shall submit the annual operating report using the DEP's Electronic Annual Operating Report (EAOR) software, unless the Title V source claims a technical or financial hardship by submitting DEP Form No. 62-210.900(5) to the DEP Division of Air Resource Management instead of using the reporting software. Emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C. Each Title V source must pay between January 15 and April 1 of each year an annual emissions fee in an amount determined as set forth in subsection 62-213.205(1), F.A.C. The annual fee shall only apply to those regulated pollutants, except carbon monoxide and greenhouse gases, for which an allowable numeric emission-limiting standard is specified in the source's most recent construction permit or operation permit. Upon completing the required EAOR entries, the EAOR Title V Fee Invoice can be printed by the source showing which of the reported emissions are subject to the fee and the total Title V Annual Emissions Fee that is due. The submission of the annual Title V emissions fee payment is also due (postmarked) by April 1st of each year. A copy of the system-generated EAOR Title V Annual Emissions Fee Invoice and the indicated total fee shall be submitted to: **Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070.** Additional information is available by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm. [Rules 62-210.370(3), 62-210.900 & 62-213.205, F.A.C.; and, §403.0872(11), Florida Statutes (2013)]

{Permitting Note: Resources to help you complete your AOR are available on the electronic AOR (EAOR) website at: http://www.dep.state.fl.us/air/emission/eaor. If you have questions or need assistance after reviewing the information posted on the EAOR website, please contact the Department by phone at (850) 717-9000 or email at eaor@dep.state.fl.us.}

{Permitting Note: The Title V Annual Emissions Fee form (DEP Form No. 62-213.900(1)) has been repealed. ***A separate Annual Emissions Fee form is no longer required to be submitted by March 1st each year.***

8. Annual Statement of Compliance. The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit within 60 days after the end of each calendar year during which the Title V permit was effective. [Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

9. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Northwest District office. Notifications and reports may be submitted by electronic mail to nwdair@dep.state.fl.us.

Department of Environmental Protection
Northwest District Waste Management/Air Resources
160 W. Government Street, Suite 308
Pensacola, Florida 32502-5794
Telephone: 850-595-8300; Fax: 850-595-8393

10. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303-8960
Telephone: 404-562-9155; Fax: 404-562-9163

11. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information. [Rule 62-213.420(4), F.A.C.]

12. When appropriate, any recording, monitoring or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one. [Rule 62-213.440, F.A.C.]

13. Source Obligation: "If a previously permitted facility or modification becomes a facility or modification which would be subject to the preconstruction review requirements of this rule if it were a proposed new facility or modification solely by virtue of a relaxation in any federally enforceable limitation on the capacity of the facility or modification to emit a pollutant (such as a restriction on hours of operation), which limitation was established after August 7, 1980, then at the time of such relaxation the preconstruction review requirements of this rule shall apply to the facility or modification as though construction had not yet commenced on it." This includes, but is not limited to, increases in the heat input or pollutant emission rates. [Rule 62-212.400(2)(g), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection [A]. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
034	Sulfur Recovery Plants J2 and J3

The Sulfur Recovery Plants J2 and J3 were built in the early 1970s and pre-date NSPS requirements, but are subject to emissions limits in Rule 62-296.409(2) & (3), F.A.C. These plants control sulfur emissions from the production and treating of sour crude oil and gas from the Jay Oil Field. Acid gas containing H_2S from oil and gas production is oxidized and reacted to form elemental sulfur by a multi stage Claus process. A minimum of 96% of the H_2S is recovered as elemental sulfur. Unconverted H_2S is thermally oxidized to SO_2 prior to discharge.

The maximum allowable potential regulated emissions are 6.83 tons per day of SO_2 for each sulfur recovery plant, limited to 2,490 tons per year total for both sulfur recovery plants.

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum acid gas feed rate to Sulfur Recovery Plants J2 and J3 is limited to 2.5 million standard cubic feet (SCF) per day per Sulfur Recovery Plant. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

A.2. Hours of Operation. This emissions unit (each Sulfur Recovery Plant) is allowed to operate continuously, i.e., 8,760 hours/year. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

A.3. Emissions Limit: Sulfur dioxide (SO_2) emissions shall not exceed 6.83 tons per calendar day per sulfur recovery plant, or a total for both sulfur recovery plants of 2,490 tons per year, at the maximum allowable operating rate of 2.5 MM SCF of acid gas feed per plant per day and an assumed maximum acid gas H_2S mole fraction of 0.81. At all lesser operating rates and acid gas mole fractions the SO_2 emissions shall not exceed 0.08 pound of SO_2 per pound of sulfur input. The allowable SO_2 emissions shall not exceed the value obtained from the following equation expressed as tons/day.

$$\text{Allowable } SO_2 = \frac{(QAG)(CAG)(32.06)(0.08)}{(380.68)(2000)}$$

Where: QAG = Acid gas flow rate, scf/d
CAG = Mole fraction of H_2S in acid gas based on most recent stack test (normally 0.77 - 0.81)
32.06 = Molecular weight of sulfur
0.08 = Allowable emission fraction of sulfur X ratio of molecular weight of SO_2 to sulfur
380.68 = scf per pound mole of any gas
2,000 = pounds per ton
[Rule 62-296.409(2), F.A.C.]

Test Methods and Procedures

A.4. SO_2 Emission Tests: SO_2 tests are required and shall be conducted once during each federal fiscal year (October 1 through September 30) for each sulfur recovery plant (J2 and/or J3) operated. [Rule 62-297.310(1) through (9), F.A.C.]

A.5. Test Methods: The test method for SO_2 shall be EPA Method 6 or as otherwise approved by the Department. [Rule 62-297.401(6), F.A.C.]

Monitoring of Operations

A.6. Permittee shall demonstrate continuing compliance with SO_2 emissions by monitoring and maintaining a record of acid gas composition, air rate, acid gas feed rate, and the sulfur plant tail gas ratio (H_2S to SO_2). An initial H_2S mole percent mean of 75.79% established from acid gas composition sampling (10 samples) beginning in January 2010, shall be used to compare subsequent acid gas sampling. Each subsequent **weekly** sample shall be added to the H_2S mole percent mean until the sample size of the mean reaches fifty-two (n = 52). Then the H_2S mole percent mean becomes a rolling average.

The acid gas sampling rolling average is set initially at **quarterly.** If a quarterly sample result is greater than one mole percent from the mean, then the sampling frequency is reset to **monthly**. If a **monthly** sample result is greater than one mole percent from the mean, then the sampling frequency is reset to **weekly**. If 12 consecutive **weekly** sample results are each less than one mole percent from the mean then the sampling frequency is reset to **monthly**. If three consecutive **monthly** sample results are each less than one mole percent from the mean then the sampling frequency is reset to **quarterly**. [Rule 62-4.070(3), F.A.C.]

Excess Emissions

A.7. Excess emissions resulting from startup, shutdown, or malfunction shall be routed to the low and high pressure flares providing best operation practices are adhered to in order to minimize emissions. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.

When excess emissions resulting from malfunctions are flared, Permittee shall immediately notify the Department in accordance with Rule 62-4.130, F.A.C. The notification shall include pertinent information as to the cause and expected duration of the problem, and what steps are being taken to correct the problem and to prevent its recurrence. Such notification does not release Permittee from any liability for failure to comply with Department rules.
[Rule 62-210.700(1), (4), (5) & (6), F.A.C.]

Recordkeeping and Reporting Requirements

A.8. Daily records of acid gas feed to the sulfur recovery plant, tons of sulfur produced, and calculated SO_2 emissions shall be maintained and made available for Department inspection. [Rule 62-4.070(3), F.A.C.]

A.9. This emissions unit is also subject to all applicable conditions contained in **Subsection K. Common Conditions.** Interim Alternative Test Methods and Procedures for Field Rate Dependant Emission Units.

Subsection B. This section addresses the following emissions unit

EU I.D.	Brief Description
035	Flares FL01 and FL02

The primary emergency flare (FL01) and the saltwater disposal system flare (FL02) were built in the early 1980s. The primary emergency flare includes continuous feed and purge streams with a pilot that has a maximum heat input of 26.0 MMBtu per hour and the JCSWD system flare with continuous feed streams and a pilot that has a maximum heat input of 0.5 MMBtu per hour. SO_2 emissions, limited by permit 1130005-001-AV, are controlled by a smokeless flare tip on each flare with a manual eductor gas system.

Total SO_2 emissions from these flares are limited to 2 tons per day, except under excess emissions conditions consistent with Rule 62-210.700(1), (5) & (6), F.A.C. Emissions are limited to specified daily limits contained in the Emissions Limit specific condition in this subsection.

These flares are not subject to NSPS requirements, but are subject to previously established emission limits and are regulated emission points.

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Hours of Operation. The flares are allowed to operate continuously, i.e., 8,760 hours/year. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

B.2. Emissions Limit: Total SO_2 emissions shall not exceed a total of 2 tons per day from both flares (FL01 and FL02) except during periods of excess emissions, during which emissions shall not exceed the following daily limits for more than four consecutive calendar days without the approval of the Department:

Month	Tons/Day	Month	Tons/Day
January	21.1	July	27.8
February	18.0	August	24.8
March	20.8	September	23.5
April	18.4	October	24.0
May	21.8	November	16.5
June	26.0	December	17.7

[Rules-62-212.300(1)(c) and 62-210.200(259)(a), F.A.C.]

{Permitting Note: These emission points should not produce visible emissions under acceptable operating conditions. Although visible emissions less than 20% opacity comply with the General Particulate Emission Limiting Standards. General Visible Emissions Standard in the Facility-Wide Conditions of 20% opacity, visible emissions of 5% to 15% opacity may suggest the presence of unacceptable operational problems.}

Monitoring of Operations

B.3. Permittee shall demonstrate compliance with the SO_2 standard by establishing and maintaining a record of the sulfur content of the process gas sent to each flare using approved ASTM methodology, with records maintained and made available for Department inspection. [Rule 62-4.070(3), F.A.C.]

Excess Emissions

B.4. Excess emissions resulting from startup, shutdown, or malfunction of the other emission units shall be routed to the low and high pressure flares providing best operation practices are adhered to in order to minimize emissions.
Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
When excess emissions resulting from malfunctions are flared, Permittee shall immediately notify the Department in accordance with Rule 62-4.130, F.A.C. The notification shall include pertinent information as to the cause and expected duration of the problem, and what steps are being taken to correct the problem and to prevent its recurrence. Such notification does not release Permittee from any liability for failure to comply with Department rules. [Rule 62-210.700(1), (5) & (6), F.A.C.]

Recordkeeping and Reporting Requirements

B.5. Daily records of flare gas flows, quantities and types of gas flared, calculated SO_2 emissions, opacity during flaring, and cause of excess emissions shall be maintained and made available for Department inspection. [Rule 62-4.070(3), F.A.C.]

B.6. This emissions unit has no regulatory based frequency for testing.

Subsection C. This section addresses the following emissions unit

EU I.D.	Brief Description
037	JCSWD Centaur Turbine (NSPS & NESHAP)

A 3600 HP Centaur turbine (EU 037), located at the Jay Central Saltwater Disposal Facility (JCSWD) was constructed in 1983. The natural gas fired turbine is subject to 40 CFR 60 Subpart GG - Stationary Gas Turbines, and may be subject to 40 CFR 63 Subpart YYYY - Stationary Combustion Turbines, at a future date, with both incorporated by reference in Rule 62-204.800(8)(b)41 and Rule 62-204.800(11)(b)81, F.A.C., respectively. In addition this unit is subject to applicable requirements of 40 CFR 60 and 63 Subpart A - General Provisions.

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. The maximum heat input for this JCSWD Centaur turbine shall not exceed 43.1 MMBtu per hour heat input. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

C.2. Methods of Operation - (i.e., Fuels). The maximum sulfur content of the natural gas is limited to 0.1% sulfur by weight. Records of the natural gas sulfur content shall be kept and made available for Department inspection. [Rules 62-4.070(3) and 62-213.440(1), F.A.C., and 40 CFR 60.333(b)]
{Permitting Note: The above sulfur limit was requested by the applicant and is more stringent than that of 40 CFR 60 Subpart GG (40 CFR 60.333(b)).}

C.3. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year. Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

C.4. Nitrogen Oxides (NO_X) emissions shall not exceed 150 parts per million at 15% O_2 dry basis (12 pounds per hour and 52.6 tons per year maximum potential to emit). This emissions unit shall be tested once prior to the submittal of and included with the Title V renewal permit application. [Rules 62-4.070(3), 62-204.800(8)(b)41 and 62-213.440(1), F.A.C., 40 CFR 60.332(c), and 40 CFR 60.332(a)2]
{Permitting Note: The above NO_X limit was requested by the applicant and is more stringent than that of 40 CFR 60 Subpart GG (40 CFR 60.332(c)).}

Monitoring of Operations/Excess Emissions

{Permitting Note: The Excess Emissions Rule at 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

C.5. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60 Subpart GG:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in 40 CFR 60.334(h)(3). The sulfur content of the fuel must be determined using total sulfur methods described in 40 CFR 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D6228-98, or Gas

Processors Association Standard 2377-86 (all of which are incorporated by reference-see 40 CFR 60.17), which measure the major sulfur compounds may be used; and

(2) N.A.

(3) Notwithstanding the provisions of 40 CFR 60.334(h)(1) of this Section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR 60.331(u), regardless of whether an existing custom schedule approved by the administrator for Subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data that show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in Section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

[Rule 62-204.800(8)(b)41, F.A.C. and 40 CFR 60.334(h)]

C.6. The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) - (2) N.A.

(3) Custom schedules

Operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. The frequency of determination of these values shall be in accordance with the EPA approved custom schedule (EPA letter dated December 8, 1980) allowing monthly analysis of fuel gas attached to this permit as Attachment 1.

[Rule 62-204.800(8)(b)41, F.A.C. and 40 CFR 60.334(i)]

C.7. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under 40 CFR 60 Subpart GG, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required in 40 CFR 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) N.A.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this Section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.1 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) N.A.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime

shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) - (4) N.A.

(5) All reports required under 40 CFR 60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

[Rule 62-204.800(8)(b)41, F.A.C. and 40 CFR 60.334(j)]

Test Methods and Procedures

C.8. (a) The owner or operator shall conduct the performance tests required in 40 CFR 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see 40 CFR 60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in Appendix A to this part to determine NO_X and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding 40 CFR 60.335(a)(4), the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in Section 6.5.6.1(a) through (e) Appendix A to 40 CFR 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_x concentrations, normalized to 15 percent O_2, is within 10 percent of the mean normalized concentration for all traverse points, then you may use three points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points shall be located along the measurement line that exhibited the highest average normalized NO_x concentration during the stratification test; or

(B) If each of the individual traverse point NO_x concentrations, normalized to 15 percent O_2, is within five percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least one meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this Section.

(b) The owner or operator shall determine compliance with the applicable NO_x emission limitation in specific condition D4 (40 CFR 60.332) and shall meet the performance test requirements of 40 CFR 60.8 as follows:

(1) For each run of the performance test, the mean NO_x emission concentration (NO_{XO}) corrected to 15 percent O_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction

equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and, units equipped with add-on emission control devices:

$$NO_X = (NO_{Xo})(P_r/P_o)^{0.5}\, e^{19\,(H_o - 0.00633)}\, (288[deg]K/Ta)^{1.53}$$

Where:

NO_X = emission concentration of NO_X at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,
NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2,
P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,
P_o = observed combustor inlet absolute pressure at test, mm Hg,
H_o = observed humidity of ambient air, g H_2O/g air,
e = transcendental constant, 2.718, and
T_a = ambient temperature, [deg] K.

(2) The 3-run performance test required by 40 CFR 60.8 must be performed within five percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in 40 CFR 60.331).
(3) - (5) N.A.
(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this Section) or as part of the initial performance test of the affected unit.
(7) - (9) N.A.
(10) If the owner or operator is required under 40 CFR 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:
(i) N.A.
(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used subject to the prior approval of the Administrator.
(11) The fuel analyses required under paragraphs 40 CFR 60.335(b)(9) and (b)(10) may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.
[Rule 62-204.800(8)(b)41, F.A.C. and 40 CFR 60.335(a)]

C.9. The owner or operator may use the following as alternatives to the reference methods and procedures specified in this Section:
(1) Instead of using the equation in 40 CFR 60.335(b)(1) of this Section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in 40 CFR 60.8 to ISO standard day conditions.

[Rule 62-204.800(8)(b)41, F.A.C. and40 CFR 60.335(c)]

C.10. The owner or operator shall determine compliance with the SO_2 standards in 40 CFR 60.333(b) as follows: fuel samples shall be collected in accordance with the EPA-approved custom schedule (Attachment 1) and analyzed for the total sulfur content of the fuel using ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see 40 CFR 60.17).
[Rule 62-204.800(8)(b)41, F.A.C. and 40 CFR 60.335(b)10]

General Provision Requirements

C.11. Permittee shall comply with all applicable requirements of 40 CFR 60 Subpart A (See attached - Appendix 40 CFR 60 Subpart A - General Conditions).

Additional MACT Requirements

C.12. The Combustion Turbine may be subject to (MACT) 40 CFR 63 Subpart YYYY - Stationary Combustion Turbines, at a future date. In accordance with 40 CFR 63.6090(b)(4), the unit does not have to meet the requirements of the subpart or Subpart A and no initial notification is required. Any future reconstruction as defined in 40 CFR 63.2, or installation of new equipment may result in the equipment becoming subject to additional requirements.
[Rule 62-204.800(11)(b)81, F.A.C. and 40 CFR 63 Subpart YYYY]

Subsection D. This section addresses the following emissions units

EU I.D.	Brief Description
038	1,000 HP Recompressor Engine with catalytic converter (NESHAP)
044	Five - 1,000 HP Recompressor Engines (with Catalytic converters (NESHAP)

Recompressor 4-stroke rich-burn Engines (EU 038 and EU 044) are subject to 40 CFR 63 Subpart ZZZZ (RICE MACT) - Stationary Reciprocating Internal Combustion Engines, because they are located at a major source of HAP emissions.

Five 1,000 Hp Ingersoll-Rand Recompressor Engines (EU 044) each with a heat input of 11.6 MMBtu per hour are equipped with catalytic converters. The catalytic converters limit the exhaust concentration of formaldehyde, to comply with 40 CFR 63 Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines incorporated by reference in Rule 62-204.800(11)(b)82, F.A.C.

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum heat input for each recompressor engine shall not exceed 11.6 MMBtu per hour heat input, based on a monthly average. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

D.2. Methods of Operation - (i.e., Fuels). The maximum sulfur content of the natural gas is limited to 0.1% sulfur by weight. Records of the natural gas sulfur content shall be kept and made available for Department inspection. [Rules 62-4.070(3) and 62-213.440(1), F.A.C.]

D.3. Hours of Operation. Emission unit 038 is allowed to operate continuously, i.e., 8,760 hours per year. Total combined hours of operation for all five engines in EU 044 shall not exceed 33,935 hours per year.
[Rules 62-4.070(3) and 62-210.200 (PTE), F.A.C.]

D.4. Engines shall only operate with the equipped catalytic converters. The operation of any of the engines while the converters are off line shall be considered excess emissions. The duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration. [Rule 62-4.070(3), F.A.C.]

Excess Emissions

D.5. Excess Emissions
(1) Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing best operational practices to minimize emissions are adhered to.
(2) The duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration. Operation of any of the recompressor engines without catalytic converters shall be considered excess emissions.
(3) Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.

(4) In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700, F.A.C.]

Test Methods and Procedures

D.6. These emissions units have no regulatory based frequency for testing.

40 CFR 63 Subpart ZZZZ (RICE MACT)

Testing Requirements

D.7. Emission limitations and operating limitations.
(a) You must comply with the emission limitations in Table 1a of this Subpart and the operating limitations in Table 1b of this Subpart which apply to you.
(b) N.A.
(c) N.A.

[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.660]

D.8. General requirements for complying with this Subpart.
(a) You must be in compliance with the emission limitations and operating limitations in this Subpart that apply to you at all times, except during periods of startup, shutdown, and malfunction.
(b) You must operate and maintain your stationary RICE, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown, and malfunction.
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6605]

D.9. Subsequent performance tests.
If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this Subpart.
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6615]

D.10. Performance tests and other procedures.
(a) You must conduct each performance test in Tables 3 and 4 of this Subpart that applies to you.
(b) Each performance test must be conducted according to the requirements in 40 CFR 63.7(e)(1) and under the specific conditions that this Subpart specifies in Table 4. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.
(c) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in 40 CFR 63.7(e)(1).
(d) You must conduct three separate test runs for each performance test required in this Section, as specified in 40 CFR 63.7(e)(3). Each test run must last at least one hour.
(e)

(1) You must use Equation 1 of this Section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 1)}$$

Where:

C_i = concentration of CO or formaldehyde at the control device inlet,

C_o = concentration of CO or formaldehyde at the control device outlet, and
R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e) (2) (i) through (iii) of this Section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \qquad \text{(Eq. 2)}$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.
0.209 = Fraction of air that is oxygen, percent/100.
F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm ^{3}/J (dscf/10 ^{6} Btu).
F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm ^{3}/J (dscf/10 ^{6} Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{co_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 3)}$$

Where:

X_{co2} = CO_2 correction factor, percent.
5.9 = 20.9 percent O_2-15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and SO_2 gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{co_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

Where:

% CO_2 = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance

test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g) (1) through (5) of this Section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h) (1) through (7) of this Section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided. [Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6620]

D.11. Monitoring, installation, operation, and maintenance requirements.
(a) N.A.
(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this Subpart, you must install, operate, and maintain each CPMS according to the requirements in 40 CFR 63.8.
(c) N.A.
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6625]

D.12. Monitoring and collection of data to demonstrate continuous compliance.
(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this Section.
(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously at all times that the stationary RICE is operating.
(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6635]

D.13. Continuous compliance demonstration with the emission limitations and operating limitations.
(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b and Tables 2a and 2b of this Subpart that apply to you according to methods specified in Table 6 of this Subpart.
(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b and Tables 2a and 2b of this Subpart that apply to you. These instances are deviations from the emission and operating limitations in this Subpart. These deviations must be reported according to the requirements in 40 CFR 63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.
(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with your startup, shutdown, and malfunction plan.
(d) Consistent with 40 CFR 63.6(e) and 40 CFR 63.7(e)(1), deviations from the emission or operating limitations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the Administrator's satisfaction that you were operating in accordance with the startup, shutdown, and malfunction plan. For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).
(e) N.A.
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6640]

Notifications

D.14. Notifications
(a) You must submit all of the notifications in 40 CFR 63.7(b) and (c), 40 CFR 63.8(e), (f)(4) and (f)(6), and
40 CFR 63.9(b) through (e), (g) and (h) that apply to you by the dates specified.
(b) (d) N.A.
(e) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in 40 CFR 63.7(b)(1).
(f) If you are required to conduct a performance test as specified in Table 4 to this Subpart, you must submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii).
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6645]

Reporting and Recordkeeping

D.15. Reporting Requirements.
(a) You must submit each report in Table 7 of this Subpart that applies to you.
(b) Unless the Administrator has approved a different schedule for submission of reports under 40 CFR 63.10(a), you must submit each report by the date in Table 7 of this Subpart and according to the requirements in paragraphs (b)(1) through (5) of this Section.

(1) The first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in 40 CFR 63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in 40 CFR 63.6595.
(2) The first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in 40 CFR 63.6595.
(3) Each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.
(4) Each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.
(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to
40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this Section.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this Section.

(1) Company name and address.
(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.
(3) Date of report and beginning and ending dates of the reporting period.
(4) If you had a startup, shutdown, or malfunction during the reporting period, the compliance report must include the information in 40 CFR 63.10 (d)(5)(i).
(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this Subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this Section and the information in paragraphs (d)(1) and (2) of this Section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this Subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this Section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in
40 CFR 63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR 70 or 71 must report all deviations as defined in this Subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this Subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this Subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) N.A.

[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6650]

D.16. Recordkeeping Requirements.
(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(3), (b)(1) through (b)(3) and (c) of this Section.

(1) A copy of each notification and report that you submitted to comply with this Subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in 40 CFR 63.10(b)(2)(xiv).

(2) The records in 40 CFR 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests and performance evaluations as required in 40 CFR 63.10(b)(2)(viii).

(b) For each CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this Section.

(1) Records described in 40 CFR 63.10(b)(2)(vi) through (xi).

(2) Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CPMS as required in 40 CFR 63.8(f)(6)(i), if applicable.

(c) N.A.
(d) You must keep the records required in Table 6 of this Subpart to show continuous compliance with each emission or operating limitation that applies to you.
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6655]

D.17. Records Format.
(a) Your records must be in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1).
(b) As specified in 40 CFR 63.10(b)(1), you must keep each record for five years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
(c) You must keep each record readily accessible in hard copy or electronic form on-site for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). You can keep the records off-site for the remaining three years.
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6660]

General Provision Requirements

D.18. 40 CFR 63.6665 - General Provisions.
Appendix to Subpart ZZZZ shows which parts of the General Provisions in 40 CFR 63.1 through 63.15 apply to you. [Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6665]

D.19. 40 CFR 63.6670 - Implementation and Enforcement of this subpart.
(a) N.A.
(b) N.A.
(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in
40 CFR 63.6600 under 40 CFR 63.6(g).

(2) Approval of major alternatives to test methods under 40 CFR 63.7(e)(2)(ii) and (f) and as defined in 40 CFR 63.90.

(3) Approval of major alternatives to monitoring under 40 CFR 63.8(f) and as defined in 40 CFR 63.90.

(4) Approval of major alternatives to recordkeeping and reporting under 40 CFR 63.10(f) and as defined in 40 CFR 63.90.
(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in 40 CFR 63.6610(b).
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR 63.6670]

D.20. Permittee shall comply with all applicable requirements of 40 CFR 63 Subpart ZZZZ (See attached - Appendix 40 CFR 63 ZZZZ).

D.21. These emissions units are also subject to all applicable conditions contained in **Subsection K - Common Conditions**.. Interim Alternative Test Methods and Procedures for Field Rate Dependant Emissions Units.

Subsection E. This section addresses the following emissions unit(s).

EU I.D.	Brief Description
039	Sulfur Storage Pits and Loading Racks

Sulfur Storage Pits (Jay 2 and Jay 3) (EU 039) store molten sulfur prior to transfer by loading racks to tanker trucks. Each storage pit holds approximately 600 tons of molten sulfur. The sulfur pits were approved in a letter from DER to Mr. C. A. Wooley, Exxon Company, U.S.A., dated January 21, 1980 (Attached).

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

E.1. Permitted Capacity. The process rate to each of the sulfur storage pits shall not exceed 75 tons per day. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C., and letter of approval to C. A. Woolley, Exxon Company, U.S.A. dated January 21, 1980]

E.2. Hours of Operation. These sulfur storage pits are allowed to operate continuously, i.e., 8,760 hours/year. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C., and letter of approval to C. A. Woolley, Exxon Company, U.S.A. dated January 21, 1980]

Emission Limitations and Standards

E.3. Visible Emissions. Visible emissions shall not exceed 20 percent opacity (six-minute average). [Rule 62-4.070(3), F.A.C.]

Excess Emissions

E.4. Excess Emissions: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Test Methods and Procedures

E.5. Visible emissions testing for each sulfur pit vent shall be conducted once prior to the submittal of and included with the Title V Renewal Permit Application. The test shall be a 30-minute test conducted in accordance with EPA method 9. The Department shall be notified at least 15 days prior to testing to allow witnessing. Results shall be submitted to the Department within 45 days after testing. The test reports shall comply with applicable portions of Rule 62-297.310, F.A.C, Test Reports. [Rules 62-4.070(3), 62-297.310(7) and 62-297.401(9), F.A.C., and letter of approval to C. A. Woolley, Exxon Company, U.S.A. dated January 21, 1980]

Monitoring of Operations

E.6. All molten sulfur transfer shall be through enclosed piping systems where feasible and practical. Contact surfaces between movable unloading arms and stationary pipes shall seat effectively around the entire circumference to minimize spillage. [Rule 62-4.070(3), F.A.C., and letter of approval to C. A. Woolley, Exxon Company, U.S.A. dated January 21, 1980]

E.7. All areas surrounding points where molten sulfur pipes are routinely disconnected and areas where molten sulfur is transferred to trucks or railcars shall be paved and curbed within 20 feet of

the point of disconnection or transfer to contain any spilled molten sulfur, or shall be provided with non-corrodible drip pans or other secondary containment, positioned to collect spills, that are adequate to contain amounts of sulfur that may escape during routine disconnection, reconnection or operation of the system. [Rule 62-4.070(3), F.A.C., and letter of approval to C. A. Woolley, Exxon Company, U.S.A. dated January 21, 1980]

E.8. All spilled molten sulfur shall be collected and properly disposed of whenever the containment area is filled to one-half its containment capacity, or monthly, whichever is more frequent. Spills of molten sulfur outside of a containment area, or where subject to vehicular traffic, shall be collected and disposed of as soon as possible, but no later than 24 hours after the spill occurs. Drip pans or other secondary containment shall be cleaned as needed to prevent exceedance of capacity, but at least weekly. [Rule 62-4.070(3), F.A.C., and letter of approval to C. A. Woolley, Exxon Company, U.S.A. dated January 21, 1980]

E.9. All vent surfaces shall be cleaned monthly to remove captured particulate. [Rule 62-4.070(3), F.A.C., and letter of approval to C. A. Woolley, Exxon Company, U.S.A. dated January 21, 1980]

Recordkeeping and Reporting Requirements

E.10. Permittee shall maintain records of spills outside of containment areas and of collection and disposal of spilled sulfur. Such records shall be retained for a minimum of two years and shall be available for inspection by the Department upon request. [Rule 62-4.070(3), F.A.C., and letter of approval to C. A. Woolley, Exxon Company, U.S.A. dated January 21, 1980]

Subsection F. This section addresses the following emissions unit

EU I.D.	Brief Description
048	Glycol Reboiler CondenserVent (NESHAP)

The Tri-Ethylene Glycol (TEG) Dehydration Unit removes water from wet natural gas from the field. The wet gas is run through an absorber column where the TEG absorbs the water from the natural gas. A Glycol Reboiler is used to remove the water from the TEG so it may be recycled through the process. The reboiler vapor is run through an air-cooled condenser to recover organics. The condenser vent is routed to a venturi burner in the flame zone of the reboiler for VOC and HAP control.

This process is regulated by 40 CFR 63 Subpart HH - Oil and Natural Gas Production Facilities. The GDU was redesigned in 2004 to comply with the MACT standard by combusting the condenser vent stream in the flame-zone of the TEG reboiler process heater with a venturi burner. This exempts Breitburn from preparing a design analysis, and conducting performance testing and monitoring.

The Glycol Reboiler used to vent only through the condenser to control VOC and HAPs emissions. The natural gas flow rate was a vital part of calculating emissions using the GRI-GLYCalc computer program and the natural gas flow rate limit was established based on the capabilities of the condenser control system. The emissions that occur now from the Tri-Ethylene Glycol Dehydration Unit are mostly the fugitive emissions from components (valves, pumps flanges and pressure relief valves, etc.). Emissions are thus not based now on process flow rates but are calculated based on emissions factors, types, and number of components. A change in inlet gas flow throughput does not result in changes to the calculated emissions rates. Permit No. 1130005-018-AC removed the natural gas throughput limits for the Glycol Reboiler Vent because emissions from this unit are now fugitive emissions calculated based on emissions factors and types and number of components. The process rate limit of 90 MMscf per day is no longer applicable and was removed by permit No. 1130005-018-AC and is being incorporated in this permit revision.

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
{Permitting Note: The following conditions are the applicable 40 CFR 63 Subpart HH requirements for this facility. Due to all 40 CFR 63 Subpart HH requirements not being applicable, the numbering system may not correlate to that of EPA's 40 CFR 63 Subpart HH (CFR published).

40 CFR 63 Subpart HH - Oil and Natural Gas Production Facilities

Emission Limitations and Standards

F.2. Glycol dehydration unit process vent standards.
The glycol dehydration unit process vent shall connect the process vent to the TEG reboiler process heater through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of 40 CFR 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of 40 CFR 63.771(d). One or more safety

devices that vent directly to the atmosphere may be used on the air emission control equipment installed to comply with 40 CFR 63.765(b)(1).
[Rule 62-204.800(11)(b)24, F.A.C. and 40 CFR 63.765]

Test Methods and Procedures

F.3. This emissions unit has no regulatory based frequency for testing.

Monitoring of Operations

F.4. Afirmative defense for violations of emission standards during malfunction.
(a) The provisions set forth in this Subpart shall apply at all times
(b)-(c) [Reserved]
(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined in 40 CFR 63.2. Appropriate penalties may be assessed; however, if you fail to meet your burden of proving all of the requirements in the affirmative defense, the affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation:

(A) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(iv) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(2) Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard
[Rule 62-204.800(11)(b)24, F.A.C. and 40 CFR 63.762]

F.5. Control equipment requirements.
(a) Closed-vent system requirements.

(1) The closed-vent system shall route all gases, vapors, and fumes emitted from the TEG reboiler vent to the TEG reboiler process heater so that the vent stream shall be introduced into the flame zone of TEG reboiler process heater.

(2) The closed-vent system shall be designed and operated with no detectable emissions.

(b) Control device requirements.

(1) The control device used to comply with 40 CFR 63 Subpart HH shall be operating at all times when gases, vapors, and fumes are vented from the HAP emissions unit or units through the closed-vent system to the control device, as required under 40 CFR 63.765, except when maintenance or repair on a unit cannot be completed without a shutdown of the control device.

[Rule 62-204.800(11)(b)24, F.A.C. and 40 CFR 63.771]

F.6. Inspection and monitoring requirements.
(1) The closed-vent system shall be inspected according to the procedures and schedule specified in the paragraphs below.

(i) For each closed-vent system joints, seams, or other connections that are permanently or semi-permanently sealed (e.g., a welded joint between two Sections of hard piping or a bolted and gasketed ducting flange), the owner or operator shall:

(A) Conduct an initial inspection according to the procedures specified in 40 CFR 63.772(c) to demonstrate that the closed-vent system operates with no detectable emissions. Inspection results shall be submitted with the Notification of Compliance Status Report as specified in 40 CFR 63.775(d)(1) or (2).

(B) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; or broken or missing caps or other closure devices. The owner or operator shall monitor a component or connection using the procedures in 40 CFR 63.772(c) to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. Inspection results shall be submitted in the Periodic Report as specified in 40 CFR 63.775(e)(s)(iii).

(2) In the event that a leak or defect is detected, the owner or operator shall repair the leak or defect as soon as practicable, except as provided in paragraph (3) below.

(i) A first attempt at repair shall be made no later than five calendar days after the leak is detected.

(ii) Repair shall be completed no later than 15 calendar days after the leak is detected.

(3) Delay of repair of a closed-vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, as defined in 40 CFR 63.761, or if the owner or operator determines that emissions resulting from immediate repair would be

greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next shutdown.

(4) Any parts of the closed-vent system that are designated, as described in paragraphs (i) and (ii) below, as unsafe to inspect are exempt from the inspection requirements of this Section if:

(i) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with this Section; and

(ii) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(5) Any parts of the closed-vent system or cover that are designated, as described below, as difficult to inspect are exempt from the inspection requirements of this Section if:

(i) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(ii) The owner or operator has a written plan that requires inspection of the equipment at least once every five years.

(6) Records shall be maintained as specified in 40 CFR 63.774(b)(5) through (8).

[Rule 62-204.800(11)(b)24, F.A.C. and 40 CFR 63.773]

Recordkeeping and Reporting Requirements

F.7. Recordkeeping Requirements.

(a) The recordkeeping provisions of 40 CFR 63 Subpart A, that apply and those that do not apply to owners and operators of sources subject to this Subpart are listed in Table 2 of 40 CFR 63 Subpart HH.

(b) Each owner or operator of a facility subject to this Subpart shall maintain the records specified below.

(1) The owner or operator of an affected source subject to the provisions of this Subpart shall maintain files of all information (including all reports and notifications) required below. The files shall be retained for at least five years following the date of each occurrence, measurement, maintenance, corrective action, report or period.

(i) All applicable records shall be maintained in such a manner that they can be readily accessed.

(ii) The most recent 12 months of records shall be retained on site or shall be accessible from a central location by computer or other means that provides access within two hours after a request.

(iii) The remaining four years of records may be retained offsite.

(iv) Records may be maintained in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.

(2) Records specified in 40 CFR 63.10(b)(2);

(3) Records identifying all parts of the cover or closed-vent system that are designated as unsafe to inspect in accordance with 40 CFR 63.773(c)(5), an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(4) Records identifying all parts of the cover or closed-vent system that are designated as difficult to inspect in accordance with 40 CFR 63.773(c)(6), an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(5) For each inspection conducted in accordance with 40 CFR 63.773(c), during which a leak or defect is detected, a record of the information specified below.

(i) The instrument identification numbers, operator name or initials, and identification of the equipment.

(ii) The date the leak or defect was detected and the date of the first attempt to repair the leak or defect.

(iii) Maximum instrument reading measured by the method specified in 40 CFR 63.772 (c) after the leak or defect is successfully repaired or determined to be non-repairable.
(iv) "Repair delayed" and the reason for the delay if a leak or defect is not repaired within 15 calendar days after discovery of the leak or defect.
(v) The name, initials, or other form of identification of the owner or operator (or designee) whose decision it was that repair could not be effected without a shutdown.
(vi) The expected date of successful repair of the leak or defect if a leak or defect is not repaired within 15 calendar days.
(vii) Dates of shutdowns that occur while the equipment is unrepaired.
(viii) The date of successful repair of the leak or defect.

(6) For each inspection conducted in accordance with 40CFR 63.773(c) during which no leaks or defects are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks or defects were detected.
(7) Information and data used to demonstrate that a piece of ancillary equipment or a compressor is not in VHAP service or not in wet gas service shall be recorded in a log that is kept in a readily accessible location.

[Rule 62-204.800(11)(b)24, F.A.C. and 40 CFR 63.774]

F.8. Reporting Requirements.
(a) The reporting provisions of Subpart A of this Part, that apply and those that do not apply to owners and operators of sources subject to this Subpart are listed in Table 2.
(b) Each owner or operator of a major source subject to this Subpart shall submit the information required by 40 CFR 63.775. The applicable requirements include:

(1) - (3) N.A.
(4) A Notification of Compliance Status report as described in paragraph (c) of this Section.
(5) Periodic Reports as described in paragraph (e) of this Section; and
(6) Startup, shutdown, and malfunction reports specified in 40 CFR 63.10(d)(5) shall be submitted as required. Separate startup, shutdown, and malfunction reports as described in 40 CFR 63.10(d)(5); are not required if the information is included in the Periodic Report specified in paragraph (e) of this Section.
(7) (8) N.A.

(c) N.A.
(d) Each owner or operator of a source subject to this Subpart shall submit a Notification of Compliance Status Report as required under 40 CFR 63.9(h) within 180 days after the compliance date specified in 40 CFR 63.760(f). In addition to the information required under 40 CFR 63.9(h); the Notification of Compliance Status Report shall include the information specified in this Section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If all of the information required under this paragraph has been submitted at any time prior to 180 days after the applicable compliance dates specified in 40 CFR 63.760(f), a separate Notification of Compliance Status Report is not required. If an owner or operator submits the information specified in paragraphs (d)(1) through (12) of this Section at different times, and/or different submittals, subsequent submittals may refer to previous submittals instead of duplicating and resubmitting the previously submitted information.

(1) If a closed-vent system and a control device other than a flare are used to comply with 40 CFR 63.764, the owner or operator shall submit the information in paragraph (d)(1)(iii) of this Section and the information in either paragraph (d)(1)(i) or (ii) of this Section.
(i) The design analysis documentation specified in 40 CFR 63.772(e)(4) of this Subpart, if the owner or operator elects to prepare a design analysis; or

(ii) If the owner or operator elects to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this Section. Results of a performance test conducted prior to the compliance date of this Subpart can be used provided that the test was conducted using the methods specified in 40 CFR 63.772(e)(3) and that the test conditions are representative of current operating conditions.

(A) The percent reduction of HAP or TOC, or the outlet concentration of HAP or TOC (parts per million by volume on a dry basis), determined as specified in 40 CFR 63.772(e)(3) of this Subpart; and

(B) The value of the monitored parameters specified in 40 CFR 63.773(d) of this Subpart, or a site-specific parameter approved by the permitting agency, averaged over the full period of the performance test.

(iii) The results of the closed-vent system initial inspections performed according to the requirements in 40 CFR 63.773(c)(2)(i) and (ii).

(2) - (6) N.A.

(7) After a title V permit has been issued to the owner or operator of an affected source, the owner or operator of such source shall comply with all requirements for compliance status reports contained in the source's title V permit, including reports required under this Subpart. After a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this Subpart, the owner or operator of such source shall submit the notification of compliance status to the appropriate permitting authority following completion of the relevant compliance demonstration activity specified in this Subpart.

(8) N.A.

(9) The owner or operator shall submit the analysis performed under 40 CFR 63.760(a)(1).

(10) The owner or operator shall submit a statement as to whether the source has complied with the requirements of this Subpart.

(e) Periodic Reports. An owner or operator of a major source shall prepare Periodic Reports in accordance with paragraphs (e)(1) and (2) of this Section and submit them to the Administrator. An owner or operator of an area source shall prepare Periodic Reports in accordance with paragraph (e)(3) of this Section and submit them to the Administrator.

(1) An owner or operator shall submit Periodic Reports semiannually beginning 60 calendar days after the end of the applicable reporting period. The first report shall be submitted no later than 240 days after the date the Notification of Compliance Status Report is due and shall cover the six month period beginning on the date the Notification of Compliance Status Report is due.

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (x) of this Section, as applicable.

(i) N.A.

(ii) N.A.

(iii) For each inspection conducted in accordance with 40 CFR 63.773(c) during which a leak or defect is detected, the records specified in 40 CFR 63.774(b)(7) must be included in the next Periodic Report.

(iv) - (vi) N.A.

(vii) The information in paragraphs (e)(2)(vii)(A) and (B) of this Section shall be stated in the Periodic Report, when applicable.

(A) No excursions.

(B) No continuous monitoring system has been inoperative, out of control, repaired, or adjusted.

(viii) - (x) N.A.

(f) Notification of process change. Whenever a process change is made, or a change in any of the information submitted in the Notification of Compliance Status Report, the owner or operator shall

submit a report within 180 days after the process change is made or as a part of the next Periodic Report as required under paragraph (e) of this Section, whichever is sooner. The report shall include:

(1) A brief description of the process change;
(2) A description of any modification to standard procedures or quality assurance procedures;
(3) Revisions to any of the information reported in the original Notification of Compliance Status Report under paragraph (d) of this Section; and
(4) Information required by the Notification of Compliance Status Report under paragraph (d) of this Section for changes involving the addition of processes or equipment.

[Rule 62-204.800(11)(b)24, F.A.C, and 40 CFR 63.775]

Subsection G. This section addresses the following emissions units

EU I.D.	Brief Description
040	Jay 2 and 3 Process Heaters - 56.7 MMBtu per hour each heater
041	Jay 2 and 3 Stabilizer Bottom Heaters - 28.4 MMBtu per hour each heater
042	Jay Plant Hot Oil Heater - 55.65 MMBtu per hour

Various gas fired Process Heaters (EU 040 - Jay 2 and Jay 3 Process Heaters, EU 041 - Jay 2 and Jay 3 Stabilizer Bottom Heaters and EU 042 - Jay Plant Hot Oil Heater) are used throughout the facility.

The Jay Plant Hot Oil Heater, which has not operated since 2008, is restarted to provide heat to the skid-mounted Natural Gas Liquids Fractionation Unit. The heater has a maximum heat input rate of 55.65 MMBtu per hour and burns approximately 481 MMscf per year of pipeline natural gas (mostly methane) with a sulfur content less than 0.1% S by weight. A natural gas liquids (NGL) Fractionating Unit removes ethane, propane, butane, iso-butane, and natural gasoline. These NGL fractions have higher heating values than methane. There are no specific regulations for this emissions unit.

These process heaters are subject to 40 CFR 63 subpart DDDDD - Emissions Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT) and are considered to be existing units which do not require controls, but are subject to the work practice, monitoring and reporting requirements. These requirements are incorporated by Rule 62-204.800(11)(b)86, F.A.C. The compliance date for these process heaters is January 31, 2016.

The following specific conditions apply to the emissions unit(s) listed above:

Test Methods and Procedures

G.1. These emissions units have no regulatory based frequency for testing**.**

G.2. 40 CFR 63 subpart DDDDD Applicability.
You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in 40 CFR 63.7575 that is located at, or is part of, a major source of HAP, except as specified in 40 CFR 63.7491. For purposes of this subpart, a major source of HAP is as defined in 40 CFR 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in 40 CFR 63.7575.
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7485]

G.3. Affected Source.
(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.
(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in 40 CFR 63.7575.
(2) N/A
(b) – (c) N/A.
(d) A boiler or process heater is existing if it is not new or reconstructed.
(e) N/A
[40 CFR 63.7490]

G.4. Compliance Date.
(a)N/A
(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in 40 CFR 63.6(i).
(c) N/A
(d) You must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.
(e) – (g) N/A
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7495]

G.5. Fuel
These units are designed to burn gas 1 fuels as defined in 40 CFR 63.7575which includes any process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels.
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7575]

Emission limitations, Work practice standards, and Operating limits

G.6. Work Practice Standards.
(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.
(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under 40 CFR 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.
(i) – (iii) N/A
(2) N/A
(3) At all times, you must operate and maintain any affected source (as defined in 40 CFR 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.
(b) As provided in 40 CFR 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.
(c) - (d) N/A
(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in 40 CFR 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in 40 CFR 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to

the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.
(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7500]

General Compliance Requirements

G.7. General requirements for complying with this subpart.
(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in 40 CFR 63.7500(f).
(b) [Reserved]
(c) – (d) N/A
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7505]

Testing, Fuel Analyses, and Initial Compliance Requirements

G.8. Initial compliance requirements and compliance date.
(a) – (d) N/A
(e) For existing affected sources (as defined in 40 CFR 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in 40 CFR 63.7495 and according to the applicable provisions in 40 CFR 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in 40 CFR 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in 40 CFR 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in 40 CFR 63.7495, except as specified in paragraph (j) of this section.
(f) – (j) N/A
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7510]

G.9. Subsequent performance tests, fuel analyses, or tune-ups.
(a) – (c) N/A
(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to 40 CFR 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in 40 CFR 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in 40 CFR 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in 40 CFR 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in 40 CFR 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.
(e) – (j) N/A
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7515]

G.10. Fuel analyses and Fuel specification.
(a) – (e) N/A
(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in 40 CFR 63.7575, you must conduct a fuel specification analyses for

mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) (3) N/A

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7521]

G.11. Initial compliance demonstration with the emission limitations, fuel specifications and work practice standards.

(a) – (d) N/A

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.7545(e).

(g) – (i) N/A

[40 CFR 63.7530]

Continuous Compliance Requirements

G.12. Continuous compliance demonstration with the emission limitations, fuel specifications and work practice standards.

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in 40 CFR 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either

on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and
(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,
(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;
(B) A description of any corrective actions taken as a part of the tune-up; and
(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.
(b) – (d) N/A
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7540(a)10)]

Notification, Reports, and Records

G.13. Notification requirements.
(a) You must submit to the Administrator all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.
(b) - (d) N/A
(e) If you are required to conduct an initial compliance demonstration as specified in 40 CFR 63.7530, you must submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to 40 CFR 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in 40 CFR 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.
(2) – (5) N/A
(6) A signed certification that you have met all applicable emission limits and work practice standards.
(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.
(8) In addition to the information required in 40 CFR 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:
(i) “This facility complies with the required initial tune-up according to the procedures in 40 CFR 63.7540(a)(10)(i) through (vi).”
(ii) “This facility has had an energy assessment performed according to 40 CFR 63.7530(e).”

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."
(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.
(1) Company name and address.
(2) Identification of the affected unit.
(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.
(4) Type of alternative fuel that you intend to use.
(5) Dates when the alternative fuel use is expected to begin and end.
(g) - (h) N/A
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7545]

G.14. Reporting Requirements.
(a) You must submit each report in Table 9 to this subpart that applies to you.
(b) Unless the EPA Administrator has approved a different schedule for submission of reports under 40 CFR 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to 40 CFR 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.
(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in 40 CFR 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in 40 CFR 63.7495.
(2) The first compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in 40 CFR 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.
(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.
(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.
(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.
(3) – (5) N/A
(d)- (e) N/A
(f) - (g) [Reserved]
(h) N/A
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7550]

G.15. Recordkeeping Requirements.
(a) - (g) N/A
(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.
(i) - (j) N/A
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7555]

G.16. Records Format.
(a) Your records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1).
(b) As specified in 40 CFR 63.10(b)(1), 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, according to 40 CFR 63.10(b)(1). You can keep the records off site for the remaining 3 years.
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7560]

Other Requirements and Information

G.17. General Provisions
Table 10 to this subpart shows which parts of the General Provisions in §40 CFR 63.1 through 63.15 apply to you.
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7565]

G.18. Implementation and Enforcement of this subpart.
(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.
(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.
(1) Approval of alternatives to the non-opacity emission limits and work practice standards in 40 CFR 63.7500(a) and (b) under 40 CFR 63.6(g).
(2) Approval of alternative opacity emission limits in 40 CFR 63.7500(a) under 40 CFR 63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under 40 CFR 63.7(e)(2)(ii) and (f) and as defined in 40 CFR 63.90, and alternative analytical methods requested under 40 CFR 63.7521(b)(2).
(4) Approval of major change to monitoring under 40 CFR 63.8(f) and as defined in 40 CFR 63.90, and approval of alternative operating parameters under 40 CFR 63.7500(a)(2) and 40 CFR 63.7522(g)(2).
(5) Approval of major change to recordkeeping and reporting under 40 CFR 63.10(e) and as defined in 40 CFR 63.90.
[Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7570]

Other Requirements

G.19. Federal Rule Requirements. In addition to the specific conditions listed above, this emissions unit is subject to applicable requirements contained in 40 CFR 63 subpart A, NSPS and NESHAP General Provisions, respectively, as well as the applicable requirements for existing, Process Heaters of 40 CFR 63 subpart DDDDD, Emissions Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters, including but not limited to notifications (which may be due prior to the compliance date), tune-ups and energy assessment, performance testing, fuel analysis, and emission limits for mercury, hydrogen chloride, PM or TSM (total selected metals), and CO. The compliance date of 40 CFR 63 subpart DDDDD for this existing process heaters is January 31, 2016. [Rule 62-204.800(11)(b)86, F.A.C. and 40 CFR 63.7545 and 63.7495(b)]

Subsection H. This section addresses the following emissions units

EU I.D.	Brief Description
045	One 5,000 HP natural gas fired Cooper-Bessemer "A" Engine - 42.0 MMBtu per hour heat input with "Clean Burn" Combustion Technology (2SLB)
046	One 2,500 HP natural gas fired Cooper-Bessemer "B" Engine - 21.0 MMBtu per hour heat input (2SLB)

The two natural gas-fired Cooper-Bessemer Engines (EU 045 and 046) are existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP. These engines do not have to meet the requirements of 40 CFR 63 Subpart ZZZZ, including initial notification requirements, in accordance with 40 CFR 63.6590(b)(3)(i).

The following specific conditions apply to the emissions unit(s) listed above:

Test Methods and Procedures

H.1. These emissions units have no regulatory based frequency of testing.

General Provision Requirements

40 CFR 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

H.2. 40 CFR63.6590 - What parts of my plant does this Subpart cover?
This Subpart applies to each affected source.
(a) Affected source. An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) Existing stationary RICE

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) - (iv) N.A.

(2) - (3) N.A.

(b) Stationary RICE subject to limited requirements

(1) - (2) N.A.

(3) The following stationary RICE do not have to meet the requirements of this Subpart and of Subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) - (v) N.A.

(c) N.A.
[Rule 62-204.800(11)(b)82, F.A.C. and 40 CFR63.6590]

Subsection I. This section addresses the following emissions unit

EU I.D.	Brief Description
050	14,300 HP (South) Water Flood Gas Turbine

A natural gas-fired Water Flood Turbine (EU 050) is regulated by Rule 62-296.320, F.A.C. A letter from DEP to Mr. Justin Thompson, Breitburn Operating LP, dated October 23, 2013states, "the Department concurs that the South Water Flood Gas Turbine is not subject to 40 CFR 60 Subpart GG, 40 CFR 60 Subpart KKKK, and 40 CFR 63 Subpart YYYY." The emissions unit's permit specific conditions are enforceable and remain in effect.

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

I.1. Permitted Capacity. The maximum allowable heat input rate for the combustion turbine shall not exceed 156.1 MMBtu per hour. {Based on facility testing at lower than capacity ~ 80% (at 124.0 MMBtu per hour), until retest the facility combustion turbine shall not exceed 136.4 MMBtu per hour.} [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.; letter received by the Department dated October 30, 2007.]

I.2. Methods of Operation - (i.e., Fuels). This emissions unit shall be fueled with natural gas only. [Rules 62-4.070(3) and 62-213.440(1), F.A.C.]

I.3. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year. [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

I.4. NO_X Emissions: NO_X emissions shall not exceed 18.2 pounds per hour (36.7 tons per year). [Rule 62-4.070(3), F.A.C. and Permit No. 1130005-012-AV]

I.5. Carbon Monoxide (CO) Emissions: CO emissions shall not exceed 47.2 pounds per hour (95.0 tons per year). [Rule 62-4.070(3), F.A.C. and Permit No. 1130005-012-AV]

Test Methods and Procedures

I.6. Nitrogen Oxides Tests: The test method for NO_X shall be EPA Method 7E, incorporated and adopted by reference in Chapter 62-297.401(7)(e), F.A.C., shall be conducted once prior to the submittal of and included with the Title V renewal permit application. The test shall be conducted by EPA Method 7E or other Department-approved method. [Rule 62-297.401(7)(e), F.A.C.]

I.7. Carbon Monoxide (CO) Tests: The test method for CO shall be EPA Method 10, incorporated and adopted by reference in Chapter 62-297.401(10), F.A.C., and shall be conducted prior to the submittal of and included with the Title V renewal permit application. The test shall be conducted by EPA Method 10 or other Department-approved method. [Rule 62-297.401(10), F.A.C.]

General Provision Requirements

I.8. This emissions unit is also subject to all applicable conditions contained in **Subsection K-Common Conditions**. Interim Alternative Test Methods and Procedures for Field Rate Dependant Emissions Units.

Subsection J. This section addresses the following emissions unit

EU I.D.	Brief Description
052	Natural Gas Liquids Fractionation Unit - skid mounted

This emissions unit processes natural gas liquids produced from the Jay Oil Field DE-C2 Tower into propane, butane and natural gasoline.

Natural gas from a well contains many natural gas liquids, including ethane, propane, butane, iso-butane, and natural gasoline. There are two basic steps to the treatment of natural gas liquids in natural gas. First, the liquids must be extracted from the natural gas. Second, these natural gas liquids must be separated (fractionated) down to their base components. These natural gas liquids are composed mainly of hydrocarbons containing one to eight carbon atoms per molecule. The separation of the hydrocarbon mixtures is performed by fractional distillation in column distillers in the Natural Gas Fractionation Unit.

The skid mounted Natural Gas Liquids Fractionation Unit consists of a depropanizer, a debutanizer, accumulators (propane and debutanizer), condensers (propane and butane), reboilers (depropanizer and debutanizer), pumps (depropanizer reflux and debutanizer reflux) and an R-G cooler. A molecular sieve helps purify gas going to the fractionation unit by removing sulfur compounds. Propane and butane not meeting sales specifications are recycled by use of an off-spec pressurized gas vessel. Natural gas from the Natural Gas liquids fractionation unit is returned to the field to aid in further oil recovery. Propane, butane and natural gasoline are temporarily stored on-site for off-site sales. The natural gasoline produced is sent to two existing 630,000 gallon crude oil storage tanks to be mixed with processed crude.

The Fractionation Unit is subject to Rules 40 CFR 60 Subpart VVa - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 and 40 CFR 60 Subpart OOOO - Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

The Natural Gas Fractionation Unit is a closed-vent system. Any gases left over after the products (propane, stable gasoline, butane, and isobutene) are extracted are re-introduced into the well field to help maintain the field pressure. The only emissions that occur are limited to the fugitive emissions from components (valves, pumps flanges and pressure relief valves, etc.). Emissions are not based on process flow rates but are calculated based on emissions factors, types, and number of components. A change in inlet gas flow throughput does not result in changes to the calculated emissions rates. The limit of 90 MMscf of natural gas per day to the Natural Gas Fractionation Unit was originally imposed to be consistent with the same limitation that has existed for years for the Tri-Ethylene Glycol Dehydration Unit. The process rate limit of 90 MMscf per day is no longer applicable and was removed by permit No. 1130005-018-AC and is being incorporated in this permit revision.

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

J.1. Hours of Operation. The hours of operation of the Fractionation Unit are not limited (8760 hours per year). [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards 40 CFR 60 Subpart VVa

J.2. Standards: General
(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of 40 CFR 60.482-1a through 60.482-10a or 40 CFR 60.480a(e) for all equipment within 180 days of initial startup.
(b) Compliance with 40 CFR 60.482-1a to 60.482-10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in 40 CFR 60.485a.
(c) N.A.
(d) Equipment that is in vacuum service is excluded from the requirements of 40 CFR 60.482-2a through 60.482-10a if it is identified as required in 40 CFR 60.486a(e)(5).
[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.482-1a]

J.3. Standards: Pumps in light liquid service.
(a)

(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485a(b), except as provided in 40 CFR 60.482-1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in 40 CFR 60.482-1a(c) and paragraphs (d), (e), and (f) of this section.
(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in 40 CFR 60.482-1a(f).

(b)

(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;
(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in 40 CFR 60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.
(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)

(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR 60.482-9a.
(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;
(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of 40 CFR 60.482-10a; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)

(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in 40 CFR 60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)

(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)

(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in 40 CFR 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in 40 CFR 60.485a(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of 40 CFR 60.482-10a, it is exempt from paragraphs (a) through (e) of this section.
(g) Any pump that is designated, as described in 40 CFR 60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.
[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.482-2a]

J.4. Standards: Pressure relief devices in gas/vapor service
(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in 40 CFR 60.485a(c).
(b)

(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in 40 CFR 60.482-9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in 40 CFR 60.485a(c).

(c) - (d) N.A.

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.482-4a]

J.5. Standards: Open-ended valves or lines
(a)

(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in 40 CFR 60.482-1a(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) - (e) N.A.

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.482-6a]

J.6. Standards: Valves in gas/vapor service and in light liquid service
(a)

(1) Each valve shall be monitored monthly to detect leaks by the methods specified in 40 CFR 60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, 40 CFR 60.482-1a(c) and (f), and 40 CFR 60.483-1a and 60.483-2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, 40 CFR 60.482-1a(c), and 40 CFR 60.483-1a and 60.483-2a.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with 40 CFR 60.483-1a or 40 CFR 60.483-2a, count the new valve as leaking when calculating the percentage of valves leaking as described in 40 CFR 60.483-2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)

(1)

(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for
2 successive months.

(d)

(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in 40 CFR 60.482-9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in 40 CFR 60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in 40 CFR 60.485a(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in 40 CFR 60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in 40 CFR 60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through 40 CFR 60.14 or 40 CFR 60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.482-7a]

J.7. Standards: Delay of repair

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with 40 CFR 60.482-10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.482-9a]

J.8. Standards: Connectors in gas/vapor service and in light liquid service

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in 40 CFR 60.482-1a(c), 40 CFR 60.482-10a, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in 40 CFR 60.485a(b) and, as applicable, 40 CFR 60.485a(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.
(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.
C_L = Number of connectors measured at 500 ppm or greater, by the method specified in 40 CFR 60.485a(b).
C_t = Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in 40 CFR 60.482-9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in 40 CFR 60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and
(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) Inaccessible, ceramic, or ceramic-lined connectors

(1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of 40 CFR 63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;
(ii) Insulated in a manner that prevents access to the connector by a monitor probe;
(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;
(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;
(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or
(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.482-11a]

J.9. Alternative standards for valves - allowable percentage of valves leaking

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in 40 CFR 60.487a(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with 40 CFR 60.482-7a(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in 40 CFR 60.485a(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in 40 CFR 60.485a(h).

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.483-1a]

J.10. Alternative standards for valves-skip period leak detection and repair

(a)

(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in 40 CFR 60.487(d)a.

(b)

(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in 40 CFR 60.482-7a.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in 40 CFR 60.482-7a but can again elect to use this section.
(5) The percent of valves leaking shall be determined as described in 40 CFR 60.485a(h).
(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.
(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with 40 CFR 60.482-7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.482-2a]

J.11. Equivalence of means of emission limitation

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.
(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.
(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.
(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.
(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.
(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.
(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.
(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.
(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.
(e)

(1) After a request for determination of equivalence is received, the Administrator will publish a notice in the FEDERAL REGISTER and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.
(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(f)
(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.
(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.484a]

Emission Limitations and Standards 40 CFR 60 Subpart OOOO

J.12. Equipment leak standards that apply to affected facilities at an onshore natural gas processing plant.
This section applies to the group of all equipment, except compressors, within a process unit.
(a) You must comply with the requirements of 40 CFR 60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in 40 CFR 60.5401.
(b) You may elect to comply with the requirements of 40 CFR 60.483-1a and 60.483-2a, as an alternative.
(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of 40 CFR 60.5402 of this subpart.
(d) You must comply with the provisions of 40 CFR 60.485a of this part except as provided in paragraph (f) of this section.
(e) You must comply with the provisions of 40 CFR 60.486a and 60.487a of this part except as provided in 40 CFR 60.5401, 60.5421, and 60.5422 of this part.
(f) You must use the following provision instead of 40 CFR 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in 40 CFR 60.17) must be used.
[Rule 62-204.800(8)(b)84, F.A.C. and 40 CFR 60.5400]

J.13. Exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants.
(a) You may comply with the following exceptions to the provisions of 40 CFR 60.5400(a) and (b).
(b)
(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in 40 CFR 60.485a(b) except as provided in 40 CFR 60.5400(c) and in paragraph (b)(4) of this section, and 40 CFR 60.482-4a(a) through (c) of Subpart VVa.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)

(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in 40 CFR 60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)

(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and 40 CFR 60.482-4a(b)(1) of subpart VVa.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of 40 CFR 60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of 40 CFR 60.482-2a(a)(1) and 60.482-7a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of 40 CFR 60.482-2a(a)(1), 60.482-7a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of 40 CFR 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in 40 CFR 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in 40 CFR 60.17).

(g) An owner or operator may use the following provisions instead of 40 CFR 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of Appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in 40 CFR 60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.
[Rule 62-204.800(8)(b)84, F.A.C. and 40 CFR 60.5401]

J.14. Alternative emission limitations for equipment leaks from onshore natural gas processing plants.
(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.
(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.
(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.
(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.
(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

[Rule 62-204.800(8)(b)84, F.A.C. and 40 CFR 60.5402]

Test Methods and Procedures 40 CFR 60 Subpart VVa

J.15. Test methods and procedures
(a) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in 40 CFR 60.8(b).
(b) The owner or operator shall determine compliance with the standards in 40 CFR 60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of Appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and
(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of Appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in 40 CFR 60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more

than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in 40 CFR 60.482-2a(e), 60.482-3a(i), 60.482-4a, 60.482-7a(f), and 60.482-10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of Appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Not Applicable. However, compliance must be demonstrated with 40 CFR 60.5400(f).

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 (incorporated by reference - see 40 CFR 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of Appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max} = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).
K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).
K_2 = 0.7084 m^4 /(MJ-sec) (metric units) = 0.087 ft^4 /(Btu-sec) (English units).

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K\sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).
C_i = Concentration of sample component "i," ppm
H_i = net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of Appendix A-6 of this part or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) (incorporated by reference-see 40 CFR 60.17) shall be used to determine the concentration of sample component "i."
(6) ASTM D2382-76 or 88 or D4809-95 (incorporated by reference-see 40 CFR 60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.
(7) Method 2, 2A, 2C, or 2D of Appendix A-7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with 40 CFR 60.483-1a or 40 CFR 60.483-2a as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L / V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves.
V_L = Number of valves found leaking.
V_T = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.
(3) The number of valves leaking shall include valves for which repair has been delayed.
(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.
(5) If the process unit has been subdivided in accordance with 40 CFR 60.482-7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.
(6) The total number of valves monitored does not include a valve monitored to verify repair.

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.485a]

{Permitting Note: Permittee can use 40 CFR 60.5401(f) instead of 40 CFR 60.485a(e) and 40 CFR 60.5401(g) instead of 40 CFR 60.485a(b)(2).}

Test Methods and Procedures 40 CFR 60 Subpart OOOO

J.16. You must determine initial compliance with the standards for each affected facility using the requirements in paragraph (f) of this section. The initial compliance period begins on October 15, 2012 or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.
(a) - (e) N.A.
(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of 40 CFR 60.5400.
(g) N.A.

[Rule 62-204.800(8)(b)84, F.A.C. and 40 CFR 60.5410]
{Permit Note: Initial Compliance performed on 8/21/2013}

Monitoring of Operations 40 CFR 60 Subpart OOOO

J.17. Continuous compliance with the standards for my gas well affected facility, centrifugal compressor affected facility, stationary reciprocating compressor affected facility, pneumatic controller affected facility, storage vessel affected facility, and affected facilities at onshore natural gas processing plants.
(a) - (e) N.A.
(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of 40 CFR 60.5400.
(g) N.A.
(h) Affirmative defense for violations of emission standards during malfunction. In response to an action to enforce the standards set forth in 40 CFR 60.5400, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in 40 CFR 60.5420(a), and must prove by a preponderance of evidence that:

(i) The violation:

(A) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and
(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and
(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and
(D) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and
(iii) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and
(iv) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
(v) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health; and
(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and
(vii) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and
(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and
(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(2) Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (h)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

[Rule 62-204.800(8)(b)84, F.A.C. and 40 CFR 60.5415]

Recordkeeping and Reporting Requirements 40 CFR 60 Subpart VVa

J.18. Recordkeeping requirements.

(a)

(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.
(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.
(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by 40 CFR 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a.

(i) Monitoring instrument identification.
(ii) Operator identification.
(iii) Equipment identification.
(iv) Date of monitoring.
(v) Instrument reading.

(b) When each leak is detected as specified in 40 CFR 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in 40 CFR60.482-7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in 40 CFR 60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in 40 CFR 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of Appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) N.A.

(e) The following information pertaining to all equipment subject to the requirements in 40 CFR 60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)

(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR 60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).

(ii) The designation of equipment as subject to the requirements of 40 CFR 60.482-2a(e), 40 CFR 60.482-3a(i), or 40 CFR 60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with 40 CFR 60.482-4a.

(4)

(i) The dates of each compliance test as required in 40 CFR 60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with 40 CFR 60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of Appendix A-7 of this part and 40 CFR 60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of Appendix A-7 of this part.

(v) Results of each calibration drift assessment required by 40 CFR 60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in 40 CFR 60.482-11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to 40 CFR 60.482-4a.

(f) The following information pertaining to all valves subject to the requirements of 40 CFR 60.482-7a(g) and (h), all pumps subject to the requirements of 40 CFR 60.482-2a(g), and all connectors subject to the requirements of 40 CFR 60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with 40 CFR 60.483-2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in 40 CFR 60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in 40 CFR 60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of 40 CFR 60.7(b) and (d) do not apply to affected facilities subject to this subpart.

Compliance must also be demonstrated with 40 CFR 60.5421(b).

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.486a]

J.19. Reporting Requirements.
(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.
(b) The initial semiannual report to the Administrator shall include the following information:
(1) Process unit identification.
(2) Number of valves subject to the requirements of 40 CFR 60.482-7a, excluding those valves designated for no detectable emissions under the provisions of 40 CFR 60.482-7a(f).
(3) Number of pumps subject to the requirements of 40 CFR 60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of 40 CFR 60.482-2a(e) and those pumps complying with 40 CFR 60.482-2a(f).
(4) Number of compressors subject to the requirements of 40 CFR 60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of 40 CFR 0.482-3a(i) and those compressors complying with 40 CFR 60.482-3a(h).
(5) Number of connectors subject to the requirements of 40 CFR 60.482-11a.
(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in 40 CFR 60.486a:
(1) N.A.
(2) For each month during the semiannual reporting period,
(i) Number of valves for which leaks were detected as described in 40 CFR 60.482-7a(b) or 40 CFR 60.483-2a,
(ii) Number of valves for which leaks were not repaired as required in 40 CFR 60.482-7a(d)(1),
(iii) Number of pumps for which leaks were detected as described in 40 CFR 60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),
(iv) Number of pumps for which leaks were not repaired as required in 40 CFR 60.482-2a(c)(1) and (d)(6),
(v) - (vi) N.A.
(vii) Number of connectors for which leaks were detected as described in 40 CFR 60.482-11a(b)
(viii) Number of connectors for which leaks were not repaired as required in 40 CFR 60.482-11a(d), and
(ix)-(x) [Reserved]
(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.
(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.
(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.
(d) An owner or operator electing to comply with the provisions of 40 CFR 60.483-1a or 60.483-2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.
(e) An owner or operator shall report the results of all performance tests in accordance with 40 CFR 60.8 of the General Provisions. The provisions of 40 CFR 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the

Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.
(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

Compliance must also be demonstrated with 40 CFR 60.5422(b) and (c)

[Rule 62-204.800(8)(b)54, F.A.C. and 40 CFR 60.487a]

Recordkeeping and Reporting Requirements 40 CFR 60 Subpart OOOO

J.20. Notification, reporting, and recordkeeping requirements.
(a) You must submit the notifications required in 40 CFR 60.7(a)(1) and (4) if you own or operate one or more of the affected facilities specified in 40 CFR 60.5365 that was constructed, modified, or reconstructed during the reporting period.
(b) Reporting requirements. You must submit annual reports containing the information specified in paragraph (b)(1) of this section to the Administrator. The initial annual report is due 30 days after the end of the initial compliance period as determined according to 40 CFR 60.5410. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraph (b)(1) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section.
(i) The company name and address of the affected facility.
(ii) An identification of each affected facility being included in the annual report.
(iii) Beginning and ending dates of the reporting period.
(iv) A certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) - (6) N.A.

(7)
(i) N.A.
(ii) All reports required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in 40 CFR 63.13 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (a)(2)(i) and (ii) of this section in paper format.

(c) Recordkeeping requirements. You must maintain the records identified as specified in 40 CFR 60.7(f). All records must be maintained for at least 5 years.

[Rule 62-204.800(8)(b)84, F.A.C. and 40 CFR 60.5420

J.21. Additional recordkeeping requirements for affected facility subject to VOC requirements for onshore natural gas processing plants.

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of 40 CFR 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of 40 CFR 60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in 40 CFR 60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in 40 CFR 60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR 60.482-4a(a). The designation of equipment subject to the provisions of 40 CFR 60.482-4a(a) must be signed by the owner or operator.

[Rule 62-204.800(8)(b)84, F.A.C. and 40 CFR 60.5421]

J.22. Additional reporting requirements for affected facility subject to VOC requirements for onshore natural gas processing plants.

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of 40 CFR 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in 40 CFR 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of 40 CFR 60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of 40 CFR 60.482-4a(a) and those pressure relief devices complying with 40 CFR 60.482-4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in 40 CFR 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in 40 CFR 60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in 40 CFR 60.5401(b)(3).

[Rule 62-204.800(8)(b)84, F.A.C. and 40 CFR 60.5422]

Subsection K. Common Conditions.

Interim Alternative Test Methods and Procedures for Field Rate Dependant Emissions Units

E.U. ID No.	Brief Description
034	Sulfur Recovery Plants J2 and J3
038	Recompressor Engine with Catalytic Converter
044	Five 1,000 HP natural gas fired Ingersol Rand Compressor Engines - 11.6 MMBtu/hr heat input
050	14,300 Hp (South) Water Flood Gas Turbine

The following conditions apply to the emissions unit(s) listed above:

K.1. The facility is allowed to complete repairs and ramp up production until April 22, 2015, as approved in a letter from DEP dated November 27, 2013. Testing Requirement in Combined Appendices shall be subordinate to the following specific conditions for the four Field Rate Dependant Emissions Units listed. Field Rate Dependant Emissions Units 038, 044, and 050 shall be subject to Testing Requirements in Combined Appendices. [Rules 62-4.070(3) and 62-297.620, F.A.C.]

K.2. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, or at the greatest practicable operating capacity of the threshold numbers listed below. Under no circumstances shall operations, including during testing, exceed the maximum allowable operation rate. [Rules 62-4.070(3), and 62-297.620, F.A.C.]

K.3. After operating capacity has exceeded 50% of the permitted maximum operating rate for 30 consecutive days, notice of testing shall be given to the Department at least 15 days prior to the start of the testing under Rule 62-297.310(7)(a)(9), F.A.C., and testing conducted at the greatest practicable operating capacity. The results of this test may be used to satisfy the requirement for annual testing under Testing Requirements in Combined Appendices for the current federal fiscal year if the facility has not yet reached or exceeded 75% of the permitted maximum for 30 consecutive days. [Rules 62-4.070(3), and 62-297.310(7), F.A.C.]

K.4. After operating capacity has exceeded 75% of the permitted maximum operating rate for 30 consecutive days, notice of testing shall be given to the Department at least 15 days prior to the start of the testing under Rule 62-297.310(7)(a)(9), F.A.C., and testing conducted at the greatest practicable operating capacity. The results of this test may be used to satisfy the requirement for annual testing under Testing Requirements in Combined Appendices for the current federal fiscal year if the facility has not yet reached or exceeded 90% of the permitted maximum for ten consecutive days. [Rules 62-4.070(3), and 62-297.310(7), F.A.C.]

K.5. After operating capacity has exceeded 90% of the permitted maximum operating rate for ten consecutive days, notice of testing shall be given to the Department at least 15 days prior to the start of the testing under Rule 62-297.310(7)(a)(9), F.A.C., and testing conducted at the greatest practicable operating capacity. The results of this test may be used to satisfy the requirement for annual testing under Testing Requirements in Combined Appendices for the current federal fiscal year. [Rules 62-4.070(3), and 62-297.310(7), F.A.C.]

K.6. After operating capacity has exceeded 90% of the permitted maximum operating rate for ten consecutive days, the facility will notify the Department that the ramping up process is reasonably completed and the facility's permitted maximum operating rate has been achieved. At this point,

Interim Alternative Test Methods and Procedures for Field Rate Dependant Emissions Units shall cease to apply and testing and operating shall be as per Testing Requirements in Combined Appendices.

Section IV. Appendices

Referenced attachments made a part of this permit:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX SS-1, STACK SAMPLING FACILITIES version dated 10/07/96
APPENDIX TV-6, TITLE V CONDITIONS version dated 06/23/06
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix 40 CFR 60 A
Appendix 40 CFR 60 GG
Appendix 40 CFR 60 VVa
Appendix 40 CFR 60 OOOO
Appendix 40 CFR 63 A
Appendix 40 CFR 63 HH
Appendix 40 CFR 63 ZZZZ
Appendix 40 CFR 63 DDDDD
Attachment 1, EPA Approved Custom Fuel Sample Schedule
Attachment-2, Sulfur Pit Approval Letter

The following appendices are not enforceable parts of this permit and are included for reference purpose only.
Appendix H, Permit History
Appendix TSAC, Time Sensitive Action Chart