United States Environmental Protection Agency
Region 8
Air Program
1595 Wynkoop Street
Denver, Colorado 80202

AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE

In accordance with the provisions of Title V of the Clean Air Act and 40 CFR Part 71 and applicable rules and regulations,

Williams Companies
Williams Four Corners, LLC/Ignacio Gas Plant

is authorized to operate air emission units and to conduct other air pollutant emitting activities in accordance with the permit conditions listed in this permit.

This source is authorized to operate at the following location:

Southern Ute Indian Reservation
SE ¼ of Section 35 and SW ¼ of Section 36, Township 34 North, Range 9 West
La Plata County, Colorado

Terms not otherwise defined in this permit have the meaning assigned to them in the referenced regulations. All terms and conditions of the permit are enforceable by EPA and citizens under the Clean Air Act.

Carl Daly, Director
Air Program
US EPA Region 8

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AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE
Williams Companies
Williams Four Corners, LLC/Ignacio Gas Plant

Permit Number: V-SU-000027-2008.00	Issue Date: January 28, 2013
Replaces Permit No.: V-SU-0027-00.00	Effective Date: March 9, 2013
	Expiration Date: March 9, 2018

The permit number cited above should be referenced in future correspondence regarding this facility.

Permit Action History

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER AND TITLE	DESCRIPTION OF REVISION
November 19, 2003	Initial Permit Issued		Permit # V-SU 0027-00.00
January 28, 2013	1st Renewal Permit Issued		Permit # V-SU-000027-2008.00

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Abbreviations and Acronyms

AR	Acid Rain
ARP	Acid Rain Program
bbls	Barrels
BACT	Best Available Control Technology
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CMS	Continuous Monitoring System (includes COMS, CEMS, CPMS, and diluent monitoring)
COMS	Continuous Opacity Monitoring System
CPMS	Continuous Parameter Monitoring System
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2-e	Carbon dioxide equivalent
DAHS	Data Acquisition and Handling System
dscf	Dry standard cubic foot
dscm	Dry standard cubic meter
EIP	Economic Incentives Programs
EPA	Environmental Protection Agency
FGD	Flue gas desulfurization
gal	Gallon
GPM	Gallons per minute
H2S	Hydrogen sulfide
HAP	Hazardous Air Pollutant
hr	Hour
Id. No.	Identification Number
kg	Kilogram
lb	Pound
MACT	Maximum Achievable Control Technology
MVAC	Motor Vehicle Air Conditioner
Mg	Megagram
MMBtu	Million British Thermal Units
mo	Month
NESHAP	National Emission Standards for Hazardous Air Pollutants
NMHC	Non-methane hydrocarbons
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
pH	Negative logarithm of effective hydrogen ion concentration (acidity)
PM	Particulate Matter
PM_{10}	Particulate matter less than 10 microns in diameter
ppm	Parts per million
ppmvd	Parts per million volume dry
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
psi	Pounds per square inch
psia	Pounds per square inch absolute
RICE	Reciprocating Internal Combustion Engine
RMP	Risk Management Plan
scfm	Standard cubic feet per minute
SNAP	Significant New Alternatives Program
SO_2	Sulfur Dioxide
tpy	Ton Per Year
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

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I. Source Information and Emission Unit Identification

I.A. Source Information

Parent Company Name: Williams Companies

Plant Operator & Name: Williams Four Corners, LLC
Ignacio Gas Plant

Plant Location: SE ¼ of Section 35 and SW ¼ of Section 36, Township 34 North, Range 9 West

Latitude 37^{o} 08.43' N, Longitude -107^{o} 47.04' West

Region: 8

State: Colorado

County: La Plata

Reservation: Within the Exterior Boundaries of Southern Ute Indian Reservation

Tribe: Southern Ute Indian Tribe

Responsible Official: Vice President and General Manager

SIC Code: 1321 - Natural Gas Liquids

AFS Plant Identification Number: 08 067 00006

Other Clean Air Act Permits: December 22, 2010, PSD Permit # PSD-SU-00027-01.00 (incorporates requirements of February 24, 1984 PSD Permit).

Description:

The Ignacio Gas Plant provides compression, dehydration, and natural gas liquids recovery for San Juan Gathering Systems, a 5,300 mile pipeline system gathering gas from the San Juan Basin which spans the southwest corner of Colorado and the northwest corner of New Mexico.

The plant conditions approximately 500 to 650 million standard cubic feet (MMscfd) of field gas per day into saleable natural gas liquids and residue gas. The primary plant operations include inlet compression, dehydration, carbon dioxide removal, natural gas liquids removal, fractionation, and storage.

I.B. Source Emission Points

Table 1 - Emission Units
Williams Companies
Williams Four Corners, LLC/Ignacio Gas Plant

Unit I.D.	Description		Control Equipment
	Natural Gas Inlet Compression - Plant A		
	Clark TLA-6, 2,000 site-rated bhp, natural gas fired engines:		
1	Installed: 1957	Modified: 1975	None
2	Installed: 1957	Modified: 1975	None
3	Installed: 1957		None
4	Installed: 1957		None
5	Installed: 1957		None
6	Installed: 1957		None
7	Installed: 1957		None
	Natural Gas Inlet Compression - Plant B		
	General Electric M3142, 10,150 site-rated bhp, natural gas fired turbine:		
8		Installed: 1972	None
	Natural Gas Inlet Compression - Plant C		
	Solar Centaur 40-T4700S (SOLONOX), 3,659 site-rated bhp, natural gas fired turbine:		
9	Serial No. 4214C41	Installed: 06/2001	None
	Methane Re- Compression		
	General Electric M3142J A/T, 10,700 site-rated bhp (12,500 with steam augementation), natural gas fired turbines:		
10	Serial No. 282514	Installed: 1984	None
11	Serial No. 282515	Installed: 1984	None
	Molecular Sieve Regeneration Heater		
	C.E. Natco MN620740009020, 18.5 MMBtu/hr, natural gas fired:		
12	Serial No. N4-0027-01	Installed: 1984	None
	Molecular Sieve Regeneration Heater –back-up		
	Struthers IF-10, 13.02 MMBtu/hr maximum design heat input, natural gas fired:		
12a	Serial No. NM085347/M050102	Installed: 1984	None
	Low Pressure Steam Production Boiler		
	Vogt CL.VV-22.5, 18.0 MMBtu/hr maximum design heat input, natural gas fired:		
13	Serial Number: 1425	Installed: 1956	None

Unit I.D.	Description	Control Equipment
14	Low Pressure Steam Production Boiler - back-up Vogt CL.VV-22.5, 18.0 MMBtu/hr maximum design heat input, natural gas fired: Serial Number: 1426 Installed: 1956	None
15	West Dehydration System 500 MMscfd Sivalls Tri-ethylene Glycol Dehydrator Still Vent; Steam heated glycol reboiler. Installed: 1992	Plant Flare (Emission Unit 23)
16	East Dehydration System 120 MMscfd Sivalls Tri-ethylene Glycol Dehydrator Still Vent; 0.75 MMBtu/hr natural gas fired glycol regenerator reboiler. Serial No. 9004-174 Installed: 1991	Thermal Oxidizer (Emission Unit 22)
17	Amine Sweetening System – Carbon Dioxide Removal 500 MMscfd Gas Sweetening System; Steam heated amine regenerator still vent: Installed: 1984	Thermal Oxidizer (Emission Unit 22)
18 19 20	Piping Component Fugitives: Pumps, pressure relief devices, open-ended valve line, valves, compressors, and flanges or other connectors that are in VOC or wet gas service associated with the following: • Compression; • Natural Gas Liquids Load-out System – Y-grade ethane pipeline, 2 propane loading racks, 1 butane loading rack, 2 natural gas loading racks; • Natural Gas Liquids Removal, Fractionation and Storage Systems – Molecular Sieve, Amine Treatment System, Turbo-Expansion Unit, Fractionation Plant, Storage Facilities; • Dehydration Systems. Pre-PSD (pre-1971) 1984 PSD (BACT) 1998 NSPS KKK:	None LDAR Program LDAR Program
21	Natural Gas Liquids Loadout System One Pipeline and Five Loading Racks. Installed: Pre-1972	Plant Flare (Emission Unit 23)
22	Thermal Oxidizer Callidus Technologies, 535.3 MMscf/yr maximum usage, 55 MMBtu/hr maximum design heat input. Serial No. 203313-000 Installed: 1999	NA
23	Plant Flare Zeeco, 233.6 MMscf/yr maximum usage. Installed: 2009	NA
24	Cooling Tower Fluor Company; 3,566 MMgal/yr maximum recirculation rate. Installed: 2008	None
25 26	Condensate Storage American Tank and Steel; 16,800 gallon tank. Installed: 1999 Unknown Manufacturer; 16,800 gallon tank. Installed: 1999	None None

Unit I.D.	Description	Control Equipment
	<u>Emergency Fire Water Pump Engine</u>	
27	384 bhp Waukesha H866D diesel fired compression ignition engine Installed: 1978	
28	305 bhp Caterpillar 4W-3798 diesel fired compression ignition engine Installed: 1985	None

Table 2 - Insignificant Emission Units
Williams Companies
Williams Four Corners, LLC/Ignacio Gas Plant

Description
1 - 24,240-gallon Methanol Storage Tank
3 - 16,800-gallon Gas Spec (Amine) Storage Tanks
2 - 500-gallon Gasoline Storage Tanks
1 - 500-gallon Diesel Storage Tank
1 - 2,940-gallon TEG Storage Tank
1 - 33,684-gallon Spent Lube Oil Storage Tank
1 - 2,400-gallon Ambitrol Storage Tank
1 - 400-gallon Phosphate Storage Tank
1 - 500-gallon Bromine Storage Tank
1 - 4,200-gallon Gas Spec (Amine) Storage Tank
1 - 15,120-gallon Gas Spec (Amine) Storage Tank
1 - 756-gallon Odorant Storage Tank
1 - 8,820-gallon Lube Oil Storage Tank
1 - 11,760-gallon Lube Oil Storage Tank
2 - 2,060-gallon Lube Oil Storage Tanks
1 - 6,300-gallon Lube Oil Storage Tank
1 - 2,000-gallon Lube Oil Storage Tank
1 - 6,300-gallon Spent Lube Oil Storage Tank
2 - 2,000-gallon Spent Lube Oil Storage Tanks
2 - 21,000-gallon Spent Lube Oil/Water Storage Tanks
1 - 6,300-gallon Spent Lube Oil/Water Storage Tank
1 - 1,000-gallon Spent Lube Oil/Water Storage Tank
1 - 264-gallon Solvent Storage Tank
1 - 719-gallon TEG Storage Tank
1 - 4,200-gallon Sulfuric Acid Storage Tank
1 - 250-gallon Sulfuric Acid Storage Tank
1 - 215,000-gallon Steam/Raw Water Storage Tank
1 - 200,000-gallon Steam/Raw Water Storage Tank
2 - 21,000-gallon Steam/Raw Water Storage Tanks
2 - 1,500-gallon Diesel Storage Tanks
2 - 300-gallon Diesel Tanks (River Water Pump Building & Fire Water Pump Generators)
1 - 120-gallon Floc Tank (River Water Pump Building)
1 – 850 gallon Lube Oil Storage Tank (steam turbine)
1 - 2,500-gallon Oil/Gasoline Storage Tank

1 - 500-gallon Solvent Storage Tank
1 - 500-gallon Betz Dearborn DN 2104 Storage Tank
1 - 200-gallon Betz Spectrus OX 1200 Tank
1 - 400-gallon Bromate MBC 781 Tank
2 - 400-gallon Cortrol OS2001 Tanks
1 - 50-gallon Hypersperse MDC 120 Tank
1 - 400-gallon Optisere HP55441 Tank
1 - 300-gallon Sodium Hydroxide Tank
1 - 500-gallon Steammate NA 0120 Tank
5 - 22,321-gallon Demethanized Mix Pressurized Tanks (pressure-control valves vent to plant flare)
10 - 42,000-gallon Propane Pressurized Tanks (pressure-control valves vent to plant flare)
2 - 260,232-gallon Butane Pressurized Tanks (pressure-control valves vent to plant flare)
2 - 214,924-gallon Natural Gas Liquid Pressurized Tanks (pressure-control valves vent to plant flare)
2 - 42,000-gallon Natural Gas Liquid Rundown Pressurized Tanks (pressure-control valves vent to plant flare)
1 – 90,000-gallon Propane Pressurized Tank (pressure-control valves vent to plant flare)
1 – 90,000-gallon Natural Gas Liquid Pressurized Tank (pressure-control valves vent to plant flare)

II. National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

II.A. 40 CFR Part 63, Subpart A - National Emission Standards for Hazardous Air Pollutants, General Provisions [40 CFR 63.1 - 63.16]

This facility is subject to the requirements of 40 CFR Part 63, Subpart A as outlined in Table 2 of 40 CFR Part 63, Subpart HH. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 63.

[40 CFR 63.764]

II.B. 40 CFR Part 63, Subpart HH - National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities [40 CFR 63.760 - 63.774]

This facility is subject to the requirements of 40 CFR Part 63, Subpart HH. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 63, Subpart HH.

II.C. Affected Sources [40 CFR 63.760(a) through (e)]

The following units are affected sources for purposes of 40 CFR Part 63, Subpart HH:

1. Each glycol dehydration unit as specified in §63.760(b)(1)(i);

2. Each storage vessel with a potential for flash emissions;

3. The group of all ancillary equipment, located at natural gas processing plants, intended to operate in volatile hazardous air pollutant (VHAP) service as determined per the requirements of §63.772(a); and

[Explanatory note: Pursuant to the definitions at §63.761, "ancillary equipment" means pumps, pressure relief devices, sampling connection systems, open-ended valves, or lines, valves, flanges, or other connectors.]

4. Compressors, located at natural gas processing plants, intended to operate in VHAP service as determined per the requirements of §63.772(a).

II.D. General Standards [40 CFR 63.764]

1. Table 2 of 40 CFR Part 63, Subpart HH specifies the General Provisions of 40 CFR Part 63, Subpart A that apply.

2. All reports required under 40 CFR Part 63, Subpart A shall be sent to the Administrator at the following address as listed in §63.13:

Director, Air and Toxics Technical Enforcement Program
Office of Enforcement, Compliance and Environmental Justice
1595 Wynkoop Street, Denver, CO 80202–1129
Mail Code 8ENF–AT

Reports may be submitted on electronic media.

3. The permittee shall comply with 40 CFR Part 63, Subpart HH as follows:

(a) For each glycol dehydration unit process vent subject to this subpart, the permittee shall comply with the following:

(i) The control requirements for glycol dehydration unit process vents specified in §63.765;
(ii) The monitoring requirements specified in §63.773; and
(iii) The recordkeeping and reporting requirements specified in §§63.774 and 63.775.

(b) For each storage vessel with the potential for flash emissions subject to this subpart, the permittee shall comply with the following:

(i) The control requirements for storage vessels specified in §63.766;
(ii) The monitoring requirements specified in §63.773; and
(iii) The recordkeeping and reporting requirements specified in §§63.774 and 63.775.

(c) For ancillary equipment and compressors subject to this subpart, the permittee shall comply with the requirements for equipment leaks specified in §63.769.

4. Exemption for ancillary equipment and compressor in VHAP service*:*

(a) The permittee is exempt from the requirements for ancillary equipment and compressors subject to this subpart if the following criteria are met:

(i) Any ancillary equipment and compressors that contain or contact a fluid (liquid or gas) must have a total VHAP concentration less than 10% by weight, as determined by the procedures specified in §63.772(a);
(ii) That ancillary equipment and compressors must operate in VHAP service less than 300 hours per calendar year; or
(iii) Any ancillary equipment and compressors exempted as specified in §63.769(b).

(b) Records of the determination that the exemption from requirements for ancillary equipment and compressors applies must be maintained as required in §63.774(d)(2).

5. In all cases where the permittee is required to repair leaks by a specified time after the leak is detected:

   (a) It is a violation of 40 CFR Part 63, Subpart HH to fail to take action to repair the leak(s) within the specified time;

   (b) If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of 40 CFR Part 63, Subpart HH.

   (c) However, if the repairs are unsuccessful and a leak is detected, the permittee shall take further action as required by the applicable provisions of this subpart.

6. The permittee shall comply with all provisions as specified in §63.762.

II.E. Control Equipment Requirements [40 CFR 63.771]

The permittee shall comply with the control equipment requirements as follows:

1. For each cover, the permittee shall comply with the cover requirements specified in §63.771(b);

2. For each closed vent system, the permittee shall comply with the closed vent system requirements specified in §63.771(c);

3. For each control device, the permittee shall comply with the applicable control device requirements specified in §63.771(d) or §63.771(f) ; and

4. For each process modification made to comply with glycol dehydration unit process vent standards at §63.765(c)(2), the permittee shall comply with the process modification standards specified in §63.771(e).

[Explanatory note: Pursuant to the definition of "control device" at §63.761, if the gas or vapor recovered from regulated equipment is used, reused, returned back to the process, or sold then the recovery system used, including piping, connections, and flow inducing devices is not considered a control device or a closed-vent system.]

II.F. Test Methods, Compliance Procedures and Compliance Determinations [40 CFR 63.772]

1. Determination of material VHAP or HAP concentration to determine the applicability of the equipment leak standards under §63.769 shall be made in accordance with the requirements specified at §63.772(a). Each piece of ancillary equipment and compressors are presumed to be in VHAP service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VHAP service or in wet gas service.

2. Determination of glycol dehydration unit flow rate or associated emissions shall be made in accordance with the requirements specified in §63.772(b).

3. The no detectable emissions test procedure shall be conducted in accordance with the requirements specified in §63.772(c).

4. The permittee shall comply with any applicable provisions specified in §63.772(d).

5. The control device performance test procedure shall be conducted in accordance with the requirements specified in §63.772(e).

6. The compliance demonstration for control device performance requirements shall be conducted in accordance with the requirements specified in §63.772(f).

7. The compliance demonstration with percent reduction performance requirements for condensers shall be conducted in accordance with the requirements specified in §63.772(g).

8. The permittee shall comply with any applicable provisions specified in §63.772(h) and §63.772(i).

II.G. Inspection and Monitoring Requirements [40 CFR 63.773]

1. For each closed-vent system or cover required by the permittee to comply with 40 CFR Part 63, Subpart HH, the permittee shall comply with the requirements specified in §63.773(c).

2. For each control device required by the permittee to comply with 40 CFR Part 63, Subpart HH, the permittee shall comply with the requirements as specified in §63.773(b) or §63773(d).

II.H. Record Keeping Requirements [40 CFR 63.774]

1. The recordkeeping provisions of 40 CFR Part 63, Subpart A, that apply are listed in Table 2 of 40 CFR Part 63, Subpart HH.

2. The permittee shall maintain the records specified in §63.774(b).

3. The permittee shall maintain the records specified in §63.774(c).

4. For glycol dehydration units operating at the facility that meets the exemption criteria in §63.764(e)(1)(i) or §63.764(e)(1)(ii), the permittee shall maintain records as specified in§63.774(d).

5. For ancillary equipment and compressor engines exempt from the control requirements under §63.764(e)(2) of this subpart, the permittee shall maintain the following records:

(a) 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; and

(b) Identification and location of ancillary equipment or compressors, located at a natural gas processing plant subject to this subpart, that is in VHAP service less than 300 hours per year.

6. The permittee shall record the following when using a flare to comply with §63.771(d):

(a) Flare design (i.e., steam-assisted, air-assisted, or non-assisted);

(b) All visible emission readings, heat content determinations, flowrate measurements, and exit velocity determinations made during the compliance determination required by §63.772(e)(2); and

(c) All hourly records and other recorded periods when the pilot flame is absent.

7. The permittee shall maintain any applicable records as specified in §63.771(g).

8. The permittee shall maintain any applicable records as specified in §63.771(h).

II.I. Reporting Requirements [40 CFR 63.775]

1. The reporting provisions of Subpart A that apply are listed in Table 2 of 40 CFR Part 63, Subpart HH.

2. The permittee shall submit the information specified in §63.775(b).

3. *Notification of Compliance Status Report.* The permittee shall submit a Notification of Compliance Status Report as required under §63.9(h) within 180 days after the compliance date specified in §63.760(f). In addition to the information required under §63.9(h), the Notification of Compliance Status Report shall include the information specified in paragraphs (d)(1) through (12) of §63.775. 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 (3). 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 §63.760(f), a separate Notification of Compliance Status Report is not required.

4. *Periodic Reports.* The permittee shall prepare Periodic Reports in accordance with §63.775(e)(2) and submit them to the Administrator semi-annually by April 1st and October 1st of each year. The report due April 1, 2013 shall cover the period from the last day of the previous reporting period through February 28, 2013. Thereafter, the report due on April 1st shall cover the prior six-month period from September 1st through the

end of February. The report due on October 1st shall cover the prior six-month period from March 1st through the end of August.

[40 CFR 63.775(e) and 40 CFR 63.10(a)(5)]

5. *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 permittee shall submit a report within 180 days after the process change is made or as a part of the next Periodic Report. The report shall include the requirements of §63.775(f).

6. The permittee shall comply with any applicable reporting provisions specified at §63.775(g).

III. National Emission Standards for Hazardous Air Pollutants from Reciprocating Internal Combustion Engines

III.A. 40 CFR Part 63, Subpart A - National Emission Standards for Hazardous Air Pollutants for Source Categories, General Provisions [40 CFR 63.1 - 63.16]

1. This facility is subject to the requirements of 40 CFR Part 63, Subpart A as outlined in Table 8 of 40 CFR Part 63, Subpart ZZZZ. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 63, Subpart A.

[40 CFR 63.6665]

III.B. 40 CFR Part 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines [40 CFR 63.6580 - 63.6675]

1. This facility is subject to the requirements of 40 CFR Part 63, Subpart ZZZZ for existing compression ignition (CI) stationary reciprocating internal combustion engines (RICE) with a site rating of less than 500 brake horsepower located at a major source of hazardous air pollutants (HAPs). Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 63, Subpart ZZZZ.

2. The permittee shall comply with provisions of 40 CFR Part 63, Subpart ZZZZ in this section of the permit for each existing emergency compression ignition engine less than 500 bhp on or before the applicable compliance date of **May 3, 2013**.

3. 40 CFR Part 63, Subpart ZZZZ applies to the following engines:

   (a) IEU – 384 bhp, Waukesha H866DSIUF diesel fired emergency fire water pump engine, constructed before June 12, 2006.

   (b) IEU – 305 bhp, Caterpillar 4W-3798 diesel fired emergency fire water pump engine, constructed before June 12, 2006.

III.C. Emission Requirements

1. Emissions from each existing compression ignition engine less than 500 bhp must meet the following emission limitations according to Table 2c of 40 CFR Part 63, Subpart ZZZZ:

   (a) Except during periods of startup:

      (i) Change oil and filter every 500 hours of operation or annually, whichever comes first;
      (ii) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and

(iii) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

(b) During periods of startup:

(i) Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which the non-startup emission limitations apply.

[40 CFR 63.6602(b)]

2. The permittee shall comply with the emission limitations in 40 CFR Part 63, Subpart ZZZZ at all times.

[40 CFR 63.6605(a)]

[Explanatory Note: As stated in Condition III.B.2, the applicable compliance date for each existing emergency compression ignition engine less than 500 bhp in 40 CFR Part 63, Subpart ZZZZ is on or before May 3, 2013.]

III.D. General Requirements

1. At all times, the permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions to the levels required by 40 CFR Part 63, Subpart ZZZZ. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if the required levels have been achieved. Determination of whether such operations and maintenance procedures are being used will be based on information available to the Administrator, which 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.

[40 CFR 63.6605(b)]

III.E. Monitoring, Installation, Collection, Operation and Maintenance Requirements

1. The permittee must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop their own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[40 CFR 63.6625(e)]

2. Each engine shall be equipped with a non-resettable hour meter.

[40 CFR 63.6625(f)]

3. The permittee must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the

engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Table 2c of Subpart ZZZZ apply.

[40 CFR 63.6625(h)]

4. The permittee may utilize an oil analysis program in accordance with §63.6625(i) to extend the specified oil change requirements for Subpart ZZZZ.

[40 CFR 63.6625(i)]

III.F. Continuous Compliance Requirements

1. The permittee shall demonstrate continuous compliance with each emission limitation, operating limitation, work practice, and management practice that applies according to the requirements of Table 6 of 40 CFR Part 63, Subpart ZZZZ.

[40 CFR 63.6640(a)]

2. The permittee must report each instance in which an emission or operating limit was not met. These instance are deviations from the emission and operating limitations and must be reported according to reporting requirements of §63.6650.

[40 CFR 63.6640(b)]

3. Deviations from the emission or operating limitations that occur during 200 hours of operation from engine startup (engine burn-in period) are not violations.

[40 CFR 63.6640(d)]

4. Rebuilt stationary RICE: Engine rebuilding means to overhaul an engine or to otherwise perform extensive service on the engine (or on a portion of the engine or engine system). For the purpose of this definition, perform extensive service means to disassemble the engine (or portion of the engine or engine system), inspect and/or replace many of the parts, and reassemble the engine (or portion of the engine or engine system) in such a manner that significantly increases the service life of the resultant engine.

[40 CFR 63.6640(d) and 40 CFR 94.11(a)]

5. The permittee must also report each instance in which the requirements in Table 8 of 40 CFR Part 63, Subpart ZZZZ, were not met.

[40 CFR 63.6640(e)]

6. The permittee must operate emergency stationary RICE according to the requirements in §63.6640(f).

[40 CFR 63.6640(f)]

III.G. Record Keeping

1. The permittee must keep the following records to comply with the emission and operating limitations:

   (a) A copy of each notification and report that was submitted to comply with 40 CFR Part 63, Subpart ZZZZ, including all documentation supporting any

Initial Notification or Notification of Compliance Status that was submitted, according to the requirements of §63.10(b)(2)(xiv);

(b) Records of the occurrence and duration of each malfunction of operation (i.e. process equipment) or the air pollution control and monitoring equipment;

(c) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii);

(d) Records of all required maintenance performed on the air pollution control equipment; and

(e) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

[40 CFR 63.6655(a)]

2. For each CEMS or CPMS, the permittee must keep the following records:

(a) Records described in §63.10(b)(2)(vi) through (xi);

(b) Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3); and

(c) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

[40 CFR 63.6655(b)]

3. The permittee must keep the records required in Table 6 of 40 CFR Part 63, Subpart ZZZZ to show continuous compliance with each emission or operating limitation that applies.

[40 CFR 63.6655(d)]

4. For each existing stationary emergency RICE, the permittee must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan.

[40 CFR 63.6655(e)]

5. For each existing emergency stationary RICE, the permittee must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter as specified in §63.6655(f).

[40 CFR 63.6655(f)]

6. The permittee must keep each record in a from suitable and readily available for expeditious review, accessible in hard copy or electronic form onsite for five (5) years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche.

[40 CFR 63.10(b)(1), 40 CFR 63.10(f), and 40 CFR 63.6660]

IV. New Source Performance Standards for Volatile Organic Liquid Storage Vessels

IV.A. 40 CFR Part 60, Subpart A – New Source Performance Standards, General Provisions

This facility is subject to the requirements of 40 CFR part 60. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart A.

[40 CFR 60.1 – 60.19]

IV.B. 40 CFR Part 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

1. This facility is subject to the requirements of 40 CFR Part 60, Subpart Kb. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart Kb.

2. 40 CFR Part 60, subpart Kb applies to the following emission units:

   (a) 24,240 gallon methanol storage tank

   (b) Two (2) 21,000 gallon spent lube oil / water storage tanks

   (c) 33,684 gallon spent lube oil storage tank

[40 CFR 60.110b – 60.117b]

IV.C. Recordkeeping Requirements

The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel for each storage vessel as specified in §60.110b(a).

[40 CFR 60.116b(b)]

V. New Source Performance Standards for Stationary Gas Turbines

V.A. Subpart A – New Source Performance Standards, General Provisions
[40 CFR 60.1 – 60.19]

1. 40 CFR Part 60, Subpart A – Standards of Performance for New Stationary Sources, General Provisions: This facility is subject to the requirements of 40 CFR Part 60, Subpart GG. As such, this facility is subject to 40 CFR Part 60, Subpart A. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart A.

[40 CFR 60.1]

V.B. Subpart GG - Standards of Performance for Stationary Gas Turbines
[40 CFR 60.40c – 60.48c]

1. Applicability

    (a) This facility is subject to the requirements of 40 CFR Part 60, Subpart GG. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart GG.

    (b) 40 CFR Part 60, Subpart GG applies to the following emission units:

        (i) Unit 9: Solar Centaur 40-T4700S (SoloNO$_X$), 3,659 site-rated bhp, 34.9 MMBtu/hr, natural gas fired turbine
        Serial Number 4214C41

        (ii) Unit 10: General Electric M3142J A/T, 10,700 site-rated bhp, 111.67 MMBtu/hr, natural gas fired turbine
        Serial Number 282514

        (iii) Unit 11: General Electric M3142J A/T, 10,700 site-rated bhp, 113.79 MMBtu/hr, natural gas fired turbine
        Serial Number 282515

[40 CFR 60.330]

2. Emission Standards

    (a) Unit 9 is subject to the NO$_X$ standard listed in Table 3.

    [40 CFR 60.332]

    (b) Units 9, 10, and 11 are subject to the SO_2 standard in Table 3.

    [40 CFR 60.333]

Table 3 - Turbine Emission Standards
Williams Field Services / Williams Four Corners
Ignacio Gas Plant

Pollutant	Emission Standard	Regulatory Reference
NO_X	Unit 9: $STD = 0.0150\frac{(14.4)}{Y} + F = 160$ ppm where: Y= 13.5 kilojoules per watt hour (manufacturer's rated heat rate at manufacturer's rated peak load. The value of Y shall not exceed 14.4 kilojoules per watt hour) and F = 0 (NO_X emission allowance for fuel bound nitrogen) and STD = allowable NO_X emissions (% by volume at 15 % oxygen and on a dry basis)	40 CFR 60.332 (a)(2)
SO_2	Units 9, Unit 10, and Unit 11: Either: (a) No owner or operator subject to the provisions of this Subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015% by volume at 15% oxygen and on a dry basis; or (b) Fuel sulfur content shall not exceed 0.8% by weight.	40 CFR 60.333(a) 40 CFR 60.333(b)

3. Unit 9 shall be exempted from the NO_X emission standard in this section when being fired with an emergency fuel. For the purpose of this requirement, the term "emergency fuel" means "a fuel fired by a gas turbine only during circumstances, such as natural gas curtailment or breakdown of delivery system, that makes it impossible to fire natural gas in the gas turbine."

[40 CFR 60.332(k), 40 CFR 60.331(r)]

V.C. Testing Requirements

1. Initial performance testing is required for off permit replacement units for turbine Units 9, 10, and 11. The permittee shall comply with the initial performance test requirements of 40 CFR 60.8(a) - (f) for measuring NO_X from replaced Unit 9 and SO_2 emissions from replaced Units 9, 10, and 11 within 60 days after achieving the maximum production rate at which the turbines will be operated, but not later than 180 days after initial startup of the turbines.

[Explanatory Note: An off permit replacement unit is any unit which meets the requirements of the Off Permit Changes section of this permit and the provisions at 40 CFR 71.6(a)(12).]

2. The permittee shall comply with the test methods and procedures of 40 CFR 60.335(a), (b), and (c) when conducting the initial performance test for NO_X for Unit 9 and for SO_2 for Units 9, 10, and 11.

[40 CFR 60.8, 40 CFR 60.335, and 40 CFR 71.6(a)(3)(i)(A)]

V.D. Monitoring Requirements

1. The permittee shall comply with the requirements of 40 CFR 60.334(h) for monitoring of sulfur content and nitrogen content of the fuel being burned in Units 9, 10, and 11.

   (a) The permittee shall monitor the total sulfur content of the fuel being fired in Units 9, 10, and 11 using one of the following methods:

      (i) The permittee shall determine the sulfur content of the fuel using the methods described in §60.335(b)(10); or
      (ii) If the total sulfur content of the fuel during the most recent performance test was less than 0.4 weight percent, the permittee may determine the sulfur content of the fuel using ASTM D4084-82, 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86; or
      (iii) The permittee shall demonstrate that gaseous fuel burned in Units 9, 10, and 11 meet the definition of natural gas pursuant to §60.331(u) using one of the following sources:

         (A) The permittee shall demonstrate 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
         (B) The permittee shall use representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20.0 grains/100 scf or less.

[40 CFR 60.334(h) - (h)(3)]

[Explanatory Note: Under §60.334(h)(2), monitoring of nitrogen content of the fuel is only required if the permittee claims an allowance for fuel-bound nitrogen. The permittee has not claimed such an allowance.]

2. The permittee shall measure NO_X emissions from Unit 9 at least once every quarter to show compliance with the requirements of 40 CFR 60.332(a)(2). To meet this requirement, the permittee shall measure the NO_X emissions from the turbine using a portable analyzer and the monitoring protocol approved by EPA, or by using a Mobile Test Van (MTV) and the monitoring protocols approved by EPA.

(a) Monitoring shall begin in the first calendar quarter following EPA notification to the applicant of the approval of the monitoring protocol.

(b) If the emission unit is inoperable for 1,500 hours or more in any calendar quarter, the permittee is exempt from conducting NO_X monitoring for the emissions unit for that quarter only.

[40 CFR 60.334(c) and 40 CFR 71.6(a)(3)(i)]

V.E. Recordkeeping Requirements

1. The permittee shall comply with the following recordkeeping requirements:

   (a) The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

   (b) The permittee shall maintain a file of all measurements, including performance testing measurements, monitoring device calibration checks, and other information required by the NSPS conditions of this permit.

2. The permittee shall comply with the following recordkeeping requirements when firing an emergency fuel:

   (a) Monitoring of fuel sulfur content shall be recorded daily while firing an emergency fuel as defined in 40 CFR 60.331(r).

   (b) Monitoring of fuel nitrogen content shall be recorded daily while firing a fuel other than pipeline-quality natural gas or while firing an emergency fuel as defined in 40 CFR 60.331(r).

3. The permittee shall keep records of all required monitoring. The records shall include the following:

   (a) The date, place, and time of sampling or measurements;

   (b) The date(s) analyses were performed;

   (c) The company or entity that performed the analyses;

   (d) The analytical techniques or methods used;

   (e) The results of such analyses; and

   (f) The operating conditions as existing at the time of sampling or measurement.

4. The permittee shall keep a record of the number of hours an emissions unit is inoperable and document the reason(s) why the emissions unit was inoperable.

5. The permittee shall retain records of all required monitoring data and support information, sample analyses, fuel supplier, fuel quality, and fuel make-up pertinent to the custom fuel monitoring schedule for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. These records shall be made available upon request by EPA Region 8. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

[40 CFR 71.6(a)(3)(ii), 40 CFR 60.7(b) and 60.7(f)]

V.F. Reporting Requirements

The permittee shall submit to EPA a written report of the results of any initial performance test(s) required in this section.

[40 CFR 71.6(a)(3)(iii) and 40 CFR 60.8(a)]

VI. New Source Performance Standards for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants

VI.A. 40 CFR Part 60, Subpart A – Standards of Performance for New Stationary Sources [40 CFR 60.1 – 60.19]

This source is subject to the requirements of 40 CFR Part 60. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart A.

[40 CFR 60.1]

VI.B. 40 CFR Part 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants [40 CFR 60.630 – 60.636]

This facility is subject to the requirements of 40 CFR Part 60, Subpart KKK. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart KKK.

[Explanatory Note: Many of the requirements of 40 CFR part 60, subpart KKK, Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants, refer to the requirements of 40 CFR Part 60, Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry.]

VI.C. Affected Facilities [40 CFR 60.630]

1. The following affected facilities in onshore natural gas processing plants that commenced construction, reconstruction, or modification after January 20, 1984, and on or before August 23, 2011 are subject to the provisions of 40 CFR Part 60, Subpart KKK:

   (a) Each compressor in VOC service or wet gas service; and

   (b) The group of all equipment except compressors within a process unit.

2. A compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered under this subpart if it is located at an onshore natural gas processing plant as defined in §60.631.

VI.D. Standards [40 CFR 60.632]

1. The permittee shall comply with the requirements of §§ 60.482-1(a), (b) and (d) and 60.482-2 through 60.482-10, except as provided in §60.633, as soon as practicable, but no later than 180 days after initial startup.

2. The permittee shall comply with the provisions of §60.485 except as provided in §60.633(f).

3. The permittee shall comply with the provisions of §§60.486 and 60.487, except as provided in §§60.633, 60.635 and 60.636.

4. The permittee shall use the following provision instead of §60.485(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless the permittee 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 E169–63, 77, or 93, E168–67, 77, or 92, or E260–73, 91, or 96 (incorporated by reference as specified in §60.17) shall be used.

[40 CFR 60.632]

VI.E. Exceptions [40 CFR 60.633]

The permittee may comply with the following exceptions to the provisions of 40 CFR Part 60, Subpart VV:

1. For each pressure relief device in gas/vapor service, the leak detection and repair requirements specified in §60.633(b);

2. For sampling connection systems, the exemption specified in §60.633(c);

3. For 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, the exemptions specified in §60.633(d);

4. For reciprocating compressors in wet gas service, the exemption specified in §60.633(f);

5. For flares used to comply with Subpart KKK, the requirements specified in §60.633(g); and

6. For determining whether equipment is in heavy or light liquid service, the provisions specified in §60.633(h).

[40 CFR 60.633]

VI.F. Recordkeeping Requirements [40 CFR 60.635]

1. The permittee shall comply with the requirements of Conditions 2 and 3 below in addition to the requirements of §60.486 of 40 CFR Part 60, Subpart VV.

[40 CFR 60.635(a)]

2. The permittee shall comply with the record keeping requirements in §60.635(b) for pressure relief devices subject to the requirements of §60.633(b)(1).

[40 CFR 60.635(b)]

3. The permittee shall comply with the following requirement in addition to the requirement of §60.486(j) of 40 CFR part 60, subpart VV:

   (a) Information and data used to demonstrate that a reciprocating compressor is in wet gas service to apply for the exemption in §60.633(f) shall be recorded in a log that is kept in a readily accessible location.

[40 CFR 60.635(c)]

VI.G. Reporting Requirements [40 CFR 60.636]

1. The permittee shall comply with the reporting requirements of §60.487 of 40 CFR Part 60, Subpart VV.

[40 CFR 60.636(a)]

2. All reports required under 40 CFR Part 60, Subpart KKK shall be sent to the Administrator at the following address as listed in §60.4:

   Director, Air and Toxics Technical Enforcement Program
   Office of Enforcement, Compliance and Environmental Justice
   1595 Wynkoop Street, Denver, CO 80202–1129
   Mail Code 8ENF–AT

[40 CFR 60.4]

3. The permittee shall include the following information in the initial semiannual report in addition to the information required in §§60.487(b)(1) through 60.487(b)(4) of 40 CFR Part 60, Subpart VV:

   (a) The number of pressure relief devices subject to the requirements of §60.633(b), except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4(a) of 40 CFR Part 60, Subpart VV and those pressure relief devices complying with §60.482-4(c) of 40 CFR Part 60, Subpart VV.

[40 CFR 60.636(b)]

4. The permittee shall include the following information in all semiannual reports in addition to the information required in §§60.487(c)(2)(i) through 60.487(c)(2)(vi) of 40 CFR Part 60, Subpart VV:

   (a) The number of pressure relief devices for which leaks were detected as required in §60.633(b)(2); and

(b) The number of pressure relief devices for which leaks were not repaired as required in §60.633(b)(3).

[40 CFR 60.636(c)]

VII. New Source Performance Standards for SO_2 Emissions from Onshore Natural Gas Processing

VII.A. 40 CFR Part 60, Subpart A – Standards of Performance for New Stationary Sources [40 CFR 60.1 – 60.19]

This source is subject to the requirements of 40 CFR Part 60. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart A.

[40 CFR 60.1]

VII.B. 40 CFR Part 60, Subpart LLL – Standards of Performance for SO_2 Emissions from Onshore Natural Gas Processing [40 CFR 60.640 – 60.648]

This facility is subject to the requirements of 40 CFR Part 60, Subpart LLL. Notwithstanding conditions in this permit, the permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart LLL.

[40 CFR 60.640(a)]

VII.C. Recordkeeping

To certify that the facility is exempt from the control requirements of Subpart LLL, the permittee shall keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than two (2) long tons per day of hydrogen sulfide expressed as sulfur.

[40 CFR 60.640(b) and 40 CFR 60.647(c)]

VIII. Requirements from December 22, 2010 PSD Permit

VIII.A. Prevention of Significant Deterioration (PSD) Permit Requirements

This source is subject to the requirements of federal PSD permit #PSD-SU-00027-01.00, issued by the EPA on December 22, 2010. Notwithstanding the conditions in this permit, the permittee shall comply with all applicable provisions in the PSD permit.

[PSD Permit #PSD-SU-00027-01.00]

VIII.B. Requirements for the 10,700 bhp Turbines (Unit 10 and Unit 11)

1. Turbine Compressor Unit 10 and Turbine Compressor Unit 11 shall each be limited to a maximum NO_X concentration in the exhaust of 138 parts per million (percent by volume at 15% oxygen and on a dry basis).

2. Turbine Compressor Unit 10 and Turbine Compressor Unit 11 shall comply with the applicable requirements of 40 CFR 60, Subpart GG.

3. Stack testing, when required, shall be performed on Turbine Compressor Unit 10 and Turbine Compressor Unit 11 according to Method 20 of 40 CFR 60, Appendix A to demonstrate compliance with the emission limits

4. A test protocol outlining a plan for compliance demonstration shall be submitted to EPA for approval 45 days in advance of any scheduled testing.

5. All performance testing required pursuant to the PSD permit shall be conducted in accordance with the time schedules and procedures contained in 40 CFR 60.8. Performance test results shall be submitted to EPA not more than 45 days after the testing date.

6. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate Turbine Compressor Unit 10 and Turbine Compressor Unit 11 in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

7. The permittee shall notify EPA not more than 48 hours after discovery (or as soon as possible) of excess emissions during periods of startup, shutdown, equipment malfunctions, or process upset. Not more than 10 days after discovery, all of the following shall be provided to EPA in writing:

   (a) The identity of the stack or other emission points where excess emissions occurred;

(b) The magnitude of excess emissions expressed in terms of the emission limits;

(c) Pertinent operating data during the time of the upset;

(d) The time and duration of the excess emissions;

(e) The identity of the equipment or process causing the upset and the suspected reasons for the upset;

(f) Steps and procedures taken during the upset period to minimize excess emissions; and

(g) Steps and procedures taken or anticipated to be taken to prevent recurrence of the upset conditions.

8. If the Administrator determines that the information submitted for excess emissions does not evidence malfunction or upset conditions, failure to meet limitations described in the PSD permit will be considered a violation of the PSD permit.

VIII.C. Requirements for the Amine Treatment System (Unit 17)

1. The amine treatment system is subject to the major modification of a major stationary source provision of the PSD regulation. BACT for the amine treatment system is as follows:

   (a) A Thermal Oxidizer with natural gas as supplemental fuel shall be operated such that it is capable of destroying VOCs emitted from the amine regenerator still vent by at least 99%; and

   (b) A Leak Detection and Repair (LDAR) program to control emissions from equipment leaks from various components (valves, seals, etc.). The LDAR program shall, at a minimum, conform to 40 CFR 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas processing Plants (NSPS KKK). The amine treatment system is not specifically subject to these standards, but they are specified as part of the BACT requirements. These components shall be clearly marked, and identified as subject to BACT requirements.

2. The emission control devices shall be inspected, monitored, maintained, and operated as per the recommendations of the manufacturer to ensure on-going satisfactory performance. The operating and maintenance plan for all control equipment, control practices, and records of such inspection, monitoring, maintenance, and operation shall be maintained at the site, and made available for review upon request.

3. Visible emissions shall not exceed 20% opacity during normal operation of the amine treatment system. During periods of startup, process modification, or adjustment of

control equipment, visible emissions shall not exceed 30% opacity for more than six (6) minutes in any 60 consecutive minutes. Opacity shall be measured by EPA Method 9.

4. Volatile organic compound (VOC) emissions of air pollutants attributable to equipment leaks at the amine treatment system shall not exceed 0.72 tons per year (tpy). Compliance with the annual limits shall be determined on a rolling 12-month total. By the end of each month, a new twelve month total shall be calculated based on the previous 12 months' data. The permittee shall calculate monthly emissions and keep a compliance record on site for review.

5. The amine treatment system shall be limited to the throughputs as listed below. During the first 12 months of operation, compliance with both the monthly and yearly production limitations shall be required. After the first 12 months of operation, compliance with only the yearly limitation shall be required. Compliance with the yearly production limits shall be determined on a rolling 12 month total. Monthly records shall be maintained by the permittee and made available for inspection upon request:

   (a) Processing (inlet flow) of natural gas shall not exceed 15,208 MMscf per month;

   (b) Processing (inlet flow) of natural gas shall not exceed 182,500 MMscf per year; and

   (c) MDEA (a mixture of alkanolamines, as absorbent to remove carbon dioxide from the natural gas) circulation rate shall not exceed 2,500 gallons per minute.

6. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate the amine treatment system in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

7. The permittee shall notify EPA not more than 48 hours after discovery (or as soon as possible) of excess emissions during periods of startup, shutdown, equipment malfunctions, or process upset. Not more than 10 days after discovery, all of the following shall be provided to EPA in writing:

   (a) The identity of the stack or other emission points where excess emissions occurred;

   (b) The magnitude of excess emissions expressed in terms of the emission limits;

   (c) Pertinent operating data during the time of the upset;

   (d) The time and duration of the excess emissions;

(e) The identity of the equipment or process causing the upset and the suspected reasons for the upset;

(f) Steps and procedures taken during the upset period to minimize excess emissions; and

(g) Steps and procedures taken or anticipated to be taken to prevent recurrence of the upset conditions.

8. If the Administrator determines that the information submitted for excess emissions does not evidence malfunction or upset conditions, failure to meet limitations described in the PSD permit will be considered a violation of the PSD permit.

9. The permittee shall submit to EPA Region 8 the record keeping format that outlines how it is maintaining compliance on an ongoing basis with the requirements for the amine treatment system.

VIII.D. Requirements for the Turbo-Expansion Unit

1. The turbo-expansion unit is subject to the provisions of major modification of a major stationary source. A review under PSD regulations has determined that BACT for VOC equipment leaks from the turbo-expansion unit is an LDAR program. The LDAR program shall, at a minimum, conform to NSPS KKK. An overall control efficiency of 50.2% is assessed for this LDAR program.

2. The turbo-expansion unit is subject to NSPS KKK.

3. The emission control devices shall be inspected, monitored, maintained, and operated as per the recommendations of the manufacturer to ensure on-going satisfactory performance. The operating and maintenance plan for all control equipment, control practices, and records of such inspection, monitoring, maintenance, and operation shall be maintained at the site, and made available for review upon request.

4. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate the turbo-expansion unit in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

5. Records of startups, shutdowns, and malfunctions shall be maintained, as required under §60.7.

6. Excess Emissions and Monitoring System Performance Reports shall be submitted as required under §60.7.

7. Performance tests shall be conducted as required under §60.8.

8. The permittee shall submit to EPA Region 8 the record keeping format that outlines how it is maintaining compliance on an ongoing basis with the requirements for the turbo-expansion unit.

VIII.E. Requirements for the West Dehydrator (Unit 15)

1. The west dehydrator is subject to the major modification of a major stationary source provision of the PSD regulation. A review under PSD regulations has determined that BACT for VOC emissions is a flare (Unit 23) with emissions not to exceed 6.7 tpy.

2. The west dehydrator shall be operated in accordance with the manufacturers' recommendations and specifications, except as otherwise provided in the PSD permit.

3. The hours of operation of the west dehydrator shall be recorded and used with other available information to quantify and report annual emissions.

4. A model run using the most recent version of GRI Gly-calc and a current extended gas analysis shall be performed annually to determine and report compliance with the allowable emission rate.

5. During any period when the flare is not operational or when emissions from the west dehydrator are not routed to the flare, the permittee shall record and report such operations to EPA. The requisite report shall be made on a semi-annual basis and shall describe the periods of time that the west dehydrator operated and emissions were not controlled by the flare, the reason why the flare was not operating and the actions taken by the permittee to allow it to resume operation of the flare.

6. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate the west dehydrator in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

7. The permittee shall notify EPA not more than 48 hours after discovery (or as soon as possible) of excess emissions during periods of startup, shutdown, equipment malfunctions, or process upset. Not more than 10 days after discovery, all of the following shall be provided to EPA in writing:

   (a) The identity of the stack or other emission points where excess emissions occurred;

   (b) The magnitude of excess emissions expressed in terms of the emission limits;

(c) Pertinent operating data during the time of the upset;

(d) The time and duration of the excess emissions;

(e) The identity of the equipment or process causing the upset and the suspected reasons for the upset;

(f) Steps and procedures taken during the upset period to minimize excess emissions; and

(g) Steps and procedures taken or anticipated to be taken to prevent recurrence of the upset conditions.

8. If the Administrator determines that the information submitted for excess emissions does not evidence malfunction or upset conditions, failure to meet limitations described in the PSD permit will be considered a violation of the PSD permit.

9. The permittee shall submit to EPA Region 8 the record keeping format that outlines how it is maintaining compliance on an ongoing basis with the requirements for west dehydrator.

VIII.F. Requirements for the East Dehydrator (Unit 16)

1. The east dehydrator is subject to the major modification of a major stationary source provision of the PSD regulation. A review under PSD regulations has determined that BACT for VOC emissions is with a thermal oxidizer (Unit 22) that currently receives and controls the emissions from the amine treatment system. The emissions limits for the thermal oxidizer when both the amine treatment system and the east dehydrator is operating shall not exceed the following:

(a) VOCs……………………………………1.16 lbs per hour and 5.1 tons per year

(b) Oxides of Nitrogen (NOx)……………......8.8 lbs per hour and 38.52 tons per year

(c) Carbon Monoxide (CO)………………5.35 lbs per hour and 23.45 tons per year

(d) Sulfur Oxides (SO_2)……………………16.0 lbs per hour and 37.1 tons per year

2. The fuel flow to the thermal oxidizer shall not exceed 55 MMBtu/hr and the flow shall be monitored by a continuous recording device.

3. The east dehydrator shall be operated in accordance with the manufacturer's recommendations and specifications, except as otherwise provided in the PSD permit.

4. Except as provided below, within 60 days of the date that the east dehydrator commences operation, the permittee shall perform a stack test to determine if the emissions from the thermal oxidizer meet the emission limits set forth.

   (a) The stack test shall be performed using EPA-approved methods. The permittee shall submit a testing protocol to the EPA for comment 30 days before the stack test. This protocol also shall serve as notification to the EPA of the pending test in order to allow a representative to be present at the test.

   (b) If EPA objects to the test protocol or any part of it, the permittee's obligation to conduct the stack test is suspended until the EPA and the permittee agree on the terms of a test protocol. Once agreement is reached, the permittee shall conduct the stack test within 45 days.

   (c) The amine treatment system and the east dehydrator shall operate at 90% or more of the permitted facility's current operation capacity for the test.

   (d) The results of the stack test shall be reported to the EPA within 45 days of the date of the test.

5. A stack test shall be performed annually to determine the effectiveness of the thermal oxidizer in controlling VOC emissions. As part of the stack test, the permittee shall measure the inlet flow and outlet flow of the thermal oxidizer in order to confirm the stated destruction of the control unit. The stack test also will be used to determine if the thermal oxidizer is controlling emissions at or below the permitted emission rate.

   The results of this test shall be provided to the EPA in an annual report. Thermal oxidizer hours of operation shall be recorded and used with the results of the annual stack tests to quantify and report annual emissions to the EPA.

6. During any period when the thermal oxidizer is not operational and the east dehydrator and the amine treatment system continue to operate, the permittee shall report such operations to the EPA. The requisite report shall be made on a semi-annual basis and shall describe the periods of time that the east dehydrator and the amine treatment system operated and emissions were not controlled by the thermal oxidizer, the reason why the thermal oxidizer was not operating and the actions taken by the permittee to allow it to resume operation of the thermal oxidizer.

7. At all times, including periods of startup, shutdown, and equipment malfunction, the permittee shall maintain and operate the east dehydrator in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but not be limited to, monitoring results, review of operating and maintenance procedures, and inspection of the permitted facility.

8. The permittee shall notify the EPA not more than 48 hours after discovery (or as soon as possible) of excess emissions during periods of startup, shutdown, equipment malfunctions, or process upset. Not more than 10 days after discovery, all of the following shall be provided to the EPA in writing:

   (a) The identity of the stack or other emission points where excess emissions occurred;

   (b) The magnitude of excess emissions expressed in terms of the emission limits;

   (c) Pertinent operating data during the time of the upset;

   (d) The time and duration of the excess emissions;

   (e) The identity of the equipment or process causing the upset and the suspected reasons for the upset;

   (f) Steps and procedures taken during the upset period to minimize excess emissions; and

   (g) Steps and procedures taken or anticipated to be taken to prevent recurrence of the upset conditions.

9. If the Administrator determines that the information submitted for excess emissions does not evidence malfunction or upset conditions, failure to meet limitations described in the PSD permit will be considered a violation of the PSD permit.

10. The permittee shall submit to EPA Region 8 the record keeping format that outlines how it is maintaining compliance on an ongoing basis with the requirements for east dehydrator.

IX. Facility-Wide Requirements

Conditions in this section of the permit apply to all emissions units located at the facility, including any units not specifically listed in Table 1 and Table 2 of the Source Emission Points section of this permit.

[40 CFR 71.6(a)(1)]

IX.A. Recordkeeping Requirements [40 CFR 71.6(a)(3)(ii)]

The permittee shall comply with the following generally applicable recordkeeping requirements:

1. If the permittee determines that his or her stationary source that emits (or has the potential to emit, without considering controls) one or more hazardous air pollutants is not subject to a relevant standard or other requirement established under 40 CFR Part 63, the permittee shall keep a record of the applicability determination on site at the source for a period of five (5) years after the determination, or until the source changes its operations to become an affected source, whichever comes first. The record of the applicability determination shall include an analysis (or other information) that demonstrates why the permittee believes the source is unaffected (e.g., because the source is an area source).

   [40 CFR 63.10(b)(3)]

2. Records shall be kept of off permit changes, as required by the Off Permit Changes section of this permit.

IX.B. Permit Shield [40 CFR 71.6(f)(3)]

1. Nothing in this permit shall alter or affect the following:

   (a) The liability of a permittee for any violation of applicable requirements prior to or at the time of permit issuance;

   (b) The ability of the EPA to obtain information under Section 114 of the Clean Air Act; or

   (c) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the Administrator under that section.

IX.C. Alternative Operating Scenarios [40 CFR 71.6(a)(9) and 40 CFR 71.6(a)(3)(ii)]

<u>Engine or Turbine Replacement/Overhaul</u>

1. Replacement of an existing permitted engine or turbine with an engine of the same make, model, horsepower rating, and configured to operate in the same manner as the engine being replaced or with a new or overhauled turbine of the same make, model, MMBtu/hr, and configured to operate in the same manner as the turbine being replaced, and which

satisfies all the provisions for Off Permit Changes under this permit, including the provisions specific to engine replacement, shall be considered an allowed alternative operating scenario under this permit.

2. Any emission limits, requirements, control technologies, testing or other provisions that apply to engines or turbines that are replaced under this Alternative Operating Scenarios section shall also apply to the replacement engines or turbines.

3. Replacement of an existing permitted engine with an engine subject to 40 CFR Part 60, Subpart IIII is not an allowed alternative operating scenario.

4. Replacement of an existing permitted engine with an engine subject to 40 CFR Part 60, Subpart JJJJ is not an allowed alternative operating scenario.

5. Replacement of an existing permitted engine not subject to 40 CFR Part 63, Subpart ZZZZ with an engine subject to 40 CFR Part 63, Subpart ZZZZ is not an allowed alternative operating scenario.

6. Replacement of an existing permitted turbine with a turbine subject to 40 CFR Part 60, Subpart KKKK is not an allowed alternative operating scenario.

7. Replacement of an existing permitted turbine with a turbine subject to 40 CFR Part 63, Subpart YYYY is not an allowed alternative operating scenario.

8. Replacement of an existing turbine not subject to 40 CFR Part 60, Subpart GG with a Turbine subject to 40 CFR Part 60, Subpart GG is not an allowed alternative operating scenario.

[Explanatory Note: This section was included to allow for off permit replacement of engines that may have existing federally enforceable limits. For replacement engines which trigger new applicable requirements (i.e., NSPS, NESHAP, etc.), the minor permit modification process (Minor Modification section of this permit) shall be utilized to maintain the permitted emission limits of the replaced engine and incorporate the new applicable requirements.]

<u>Thermal Oxidizer Maintenance/Repair</u>

The use of a backup thermal oxidizer (Unit ID 22a) with equivalent capacity and emissions destruction efficiency, and configured to operate in the same manner as the primary thermal oxidizer (Unit ID 22) shall be an allowed alternative operating scenario under this permit.

1. Any emission limits, requirements, testing or other provisions that apply to primary thermal oxidizer shall also apply to the backup thermal oxidizer except that an annual performance test shall only be conducted on the backup thermal oxidizer Unit 22a if the unit operates for more than 500 hours in any calendar year.

2. At no time shall the backup thermal oxidizer operate at the same time the primary thermal oxidizer is operating.

IX.D. Reporting Requirements

1. The permittee shall submit to the EPA Regional Office all reports of any required monitoring under this permit semiannually. The report shall be submitted semi-annually, by April 1st and October 1st of each year. The report due April 1st, 2013 shall cover the period from the last day of the previous reporting period through February 28, 2013. Thereafter, the report due on April 1st shall cover the prior six-month period from September 1st through the end of February. The report due on October 1st shall cover the prior six-month period from March 1st through the end of August. All instances of deviations from permit requirements shall be clearly identified in such reports. All required reports shall be certified by a responsible official consistent with the Submissions section of this permit.

[Explanatory note: To help Part 71 permittees meet reporting responsibilities, EPA has developed a form "SIXMON" for 6 month monitoring reports. The form may be found on EPA's website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

2. "Deviation" means any situation in which an emissions unit fails to meet a permit term or condition. A deviation is not always a violation. A deviation can be determined by observation or through review of data obtained from any testing, monitoring, or recordkeeping established in accordance with §71.6(a)(3)(i) and (a)(3)(ii). For a situation lasting more than 24 hours which constitutes a deviation, each 24 hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

   (a) A situation where emissions exceed an emission limitation or standard;

   (b) A situation where process or emissions control device parameter values indicate that an emission limitation or standard has not been met; or

   (c) A situation in which observations or data collected demonstrate noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit.

3. The permittee shall promptly report to the EPA deviations from permit requirements, including those attributable to upset conditions as defined in this permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. "Prompt" is defined as follows:

   (a) Any definition of "prompt" or a specific time frame for reporting deviations provided in an underlying applicable requirement as identified in this permit;

   (b) Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

(i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report must be made within 24 hours of the occurrence.

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continues for more than two (2) hours in excess of permit requirements, the report must be made within 48 hours.

(iii) For all other deviations from permit requirements, the report shall be submitted with the semi-annual monitoring report.

(c) If any of the conditions in (i) or (ii) of paragraph (b) above are met, the permittee must notify the EPA by telephone (1-800-227-8917), fax (303-312-6064), or email (r8airreportenforcement@epa.gov) based on the timetables listed above. *[Notification by telephone, fax, or email must specify that this notification is a deviation report for a Part 71 permit].* A written notice, certified consistent with the Submissions section of this permit must be submitted within 10 working days of the occurrence. All deviations reported under this section must also be identified in the six-month report required under Condition 1 in this section of the permit.

[Explanatory note: To help Part 71 permittees meet reporting responsibilities, EPA has developed a form "PDR" for prompt deviation reporting. The form may be found on EPA's website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

IX.E. Chemical Accident Prevention [Clean Air Act Sections 112(r)(1), 112(r)(3), 112(r)(7) & 40 CFR Part 68]

This facility is subject to 40 CFR Part 68 and shall certify compliance with all requirements of 40 CFR Part 68, including the registration and submission of the RMP, as part of the annual compliance certification required by the Compliance Requirements section of this permit.

[40 CFR 68.215(a)(ii)]

IX.F. Prevention of Significant Deterioration (PSD) [40 CFR 52.21]

This facility is a major stationary source (potential to emit of any criteria pollutant > 250 tpy or CO_2-e > 100,000 tpy) for the purposes of PSD requirements (40 CFR 52.21). Future modifications to this facility which meet the definition of "major modification" in 40 CFR 52.21(b)(2) would require that Ignacio first obtain a pre-construction permit pursuant to federal regulations.

[40 CFR 52.21]

IX.G. Compliance Assurance Monitoring (CAM) [40 CFR 64]

1. The CAM requirements specified at 40 CFR Part 64 apply to the following emission units with respect to the VOC emission limits identified in the PSD Permit Requirements section of this permit:

(a) Unit 15: West Dehydration System (controlled by Flare Unit 23)

(b) Unit 16: East Dehydration System (controlled by Thermal Oxidizer Unit 22)

(c) Unit 17: Amine Sweetening System (controlled by Thermal Oxidizer Unit 22)

[40 CFR 64.2(a)]

2. The permittee shall follow the CAM plan provided as an appendix to this permit for Unit 15 (West Dehydration System), Unit 16 (East Dehydration System) and Unit 17 (Amine Sweetening System).

3. Excursions, as defined in the CAM plan, shall be reported in accordance with the Facility-Wide Reporting Requirements section of this permit.

4. Operation of Approved Monitoring

(a) At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

[40 CFR 64.7(b)]

(b) Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

[40 CFR 64.7(c)]

(c) Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

[40 CFR 64.7(d)(1)]

(d) Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(2)]

(e) After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the EPA and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

[40 CFR 64.7(e)]

5. Based on the results of a determination made under §64.7(d)(2) and Condition 4.d. above, EPA may require the permittee to develop and implement a Quality Improvement Plan (QIP) in accordance with §64.8.

[40 CFR 64.8(a)]

6. The permittee shall submit monitoring reports in accordance with §64.9(a) for CAM requirements on a semi-annual basis to EPA as specified in the Facility-Wide Reporting Requirements section in this permit.

[40 CFR 64.9(a)]

7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written QIP required pursuant to Condition 5 above and any activities undertaken to implement at QIP, and other supporting information required to be maintained under Part 64 (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions as specified in §64.9(b).

[40 CFR 64.9(b)]

X. Part 71 Administrative Requirements

X.A. Annual Fee Payment [40 CFR 71.6(a)(7) and 40 CFR 71.9]

1. The permittee shall pay an annual permit fee in accordance with the procedures outlined below.

   [40 CFR 71.9(a)]

2. The permittee shall pay the annual permit fee each year no later than April 1st. The fee shall cover the previous calendar year.

   [40 CFR 71.9(h)]

3. The fee payment shall be in United States currency and shall be paid by money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the order of the U.S. Environmental Protection Agency.

   [40 CFR 71.9(k)(1)]

4. The permittee shall send fee payment and a completed fee filing form to:

For <u>regular U.S. Postal Service mail</u>	**For <u>non-U.S. Postal Service express mail</u>** (FedEx, Airborne, DHL, and UPS)
U.S. Environmental Protection Agency FOIA and Miscellaneous Payments Cincinnati Finance Center P.O. Box 979078 St. Louis, MO 63197-9000	U.S. Bank Government Lockbox 979078 U.S. EPA FOIA & Misc. Payments 1005 Convention Plaza SL-MO-C2-GL St. Louis, MO 63101

   [40 CFR 71.9(k)(2)]

5. The permittee shall send an updated fee calculation worksheet form and a photocopy of each fee payment check (or other confirmation of actual fee paid) submitted annually by the same deadline as required for fee payment to the address listed in the Submissions section of this permit.

   [40 CFR 71.9(h)(1)]

   [Explanatory note: The fee filing form "FF" and the fee calculation worksheet form "FEE" may be found on EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

6. Basis for calculating annual fee:

   (a) The annual emissions fee shall be calculated by multiplying the total tons of actual emissions of all "regulated pollutants (for fee calculation)" emitted from the source by the presumptive emissions fee (in dollars/ton) in effect at the time of calculation.

   [40 CFR 71.9(c)(1)]

(i) “Actual emissions” means the actual rate of emissions in tpy of any regulated pollutant (for fee calculation) emitted from a Part 71 source over the preceding calendar year. Actual emissions shall be calculated using each emissions unit’s actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year.

[40 CFR 71.9(c)(6)]

(ii) Actual emissions shall be computed using methods required by the permit for determining compliance, such as monitoring or source testing data.

[40 CFR 71.9(h)(3)]

(iii) If actual emissions cannot be determined using the compliance methods in the permit, the permittee shall use other federally recognized procedures.

[40 CFR 71.9(e)(2)]

[Explanatory note: The presumptive fee amount is revised each calendar year to account for inflation, and it is available from EPA prior to the start of each calendar year.]

(b) The permittee shall exclude the following emissions from the calculation of fees:

(i) The amount of actual emissions of each regulated pollutant (for fee calculation) that the source emits in excess of 4,000 tons per year;

[40 CFR 71.9(c)(5)(i)]

(ii) Actual emissions of any regulated pollutant (for fee calculation) already included in the fee calculation; and

[40 CFR 71.9(c)(5)(ii)]

(iii) The quantity of actual emissions (for fee calculation) of insignificant activities [defined in §71.5(c)(11)(i)] or of insignificant emissions levels from emissions units identified in the permittee’s application pursuant to §71.5(c)(11)(ii).

[40 CFR 71.9(c)(5)(iii)]

7. Fee calculation worksheets shall be certified as to truth, accuracy, and completeness by a responsible official.

[40 CFR 71.9(h)(2)]

[Explanatory note: The fee calculation worksheet form already incorporates a section to help you meet this responsibility.]

8. The permittee shall retain fee calculation worksheets and other emissions-related data used to determine fee payment for five (5) years following submittal of fee payment.

[Emission-related data include, for example, emissions-related forms provided by the EPA and used by the permittee for fee calculation purposes, emissions-related spreadsheets, and emissions-related data, such as records of emissions monitoring data and related support information required to be kept in accordance with §71.6(a)(3)(ii).]

[40 CFR 71.9(i)]

9. Failure of the permittee to pay fees in a timely manner shall subject the permittee to assessment of penalties and interest in accordance with §71.9(l).

[40 CFR 71.9(l)]

10. When notified by the EPA of underpayment of fees, the permittee shall remit full payment within 30 days of receipt of notification.

[40 CFR 71.9(j)(2)]

11. A permittee who thinks an EPA assessed fee is in error and who wishes to challenge such fee, shall provide a written explanation of the alleged error to the EPA along with full payment of the EPA assessed fee.

[40 CFR 71.9(j)(3)]

X.B. Annual Emissions Inventory [40 CFR 71.9(h)(1)and (2)]

1. The permittee shall submit an annual emissions report of its actual emissions for both criteria pollutants and regulated HAPS for this facility for the preceding calendar year for fee assessment purposes. The annual emissions report shall be certified by a responsible official and shall be submitted each year to the EPA by April 1st.

2. The annual emissions report shall be submitted to the EPA at the address listed in the Submissions section of this permit.

[Explanatory note: An annual emissions report, required at the same time as the fee calculation worksheet by §71.9(h), has been incorporated into the fee calculation worksheet form as a convenience.]

X.C. Compliance Requirements

1. Compliance with the Permit

   (a) The permittee must comply with all conditions of this Part 71 permit. Any permit noncompliance constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

[40 CFR 71.6(a)(6)(i)]

(b) It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

[40 CFR 71.6(a)(6)(ii)]

(c) For the purpose of submitting compliance certifications in accordance with §71.6(c)(5), or establishing whether or not a person has violated or is in violation of any requirement of this permit, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[Section 113(a) and 113(e)(1) of the Act, 40 CFR 51.212, 52.12, 52.33, 60.11(g), and 61.12.]

2. Compliance Schedule

(a) For applicable requirements with which the source is in compliance, the source will continue to comply with such requirements.

[40 CFR 71.5(c)(8)(iii)(A)]

(b) For applicable requirements that will become effective during the permit term, the source shall meet such requirements on a timely basis.

[40 CFR 71.5(c)(8)(iii)(B)]

3. Compliance Certifications

The permittee shall submit to the EPA a certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices annually by April 1st, and shall cover the same 12 month period as the two (2) consecutive semi-annual monitoring reports.

[Explanatory note: To help Part 71 permittees meet reporting responsibilities, the EPA has developed a reporting form for annual compliance certifications. The form may be found on the EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

The compliance certification shall be certified as to truth, accuracy, and completeness by a responsible official consistent with §71.5(d).

[40 CFR 71.6(c)(5)]

(a) The certification shall include the following:

(i) Identification of each permit term or condition that is the basis of the certification;

(ii) The identification of the method(s) or other means used for determining the compliance status of each term and condition during the certification period, and whether such methods or other means provide continuous or intermittent data. Such methods and other means shall include, at a minimum, the methods and means required in this permit. If necessary, the permittee also shall identify any other material information that must be included in the certification to comply with Section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information;

(iii) The status of compliance with each term and condition of the permit for the period covered by the certification based on the method or means designated in (ii) above. The certification shall identify each deviation and take it into account in the compliance certification;

(iv) Such other facts as the EPA may require to determine the compliance status of the source; and

(v) Whether compliance with each permit term was continuous or intermittent.

[40 CFR 71.6(c)(5)(iii)]

X.D. Duty to Provide and Supplement Information
[40 CFR 71.6(a)(6)(v), 71.5(a)(3), and 71.5(b)]

1. The permittee shall furnish to the EPA, within a reasonable time, any information that the EPA may request in writing to determine whether cause exists for modifying, revoking, and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the EPA copies of records that are required to be kept pursuant to the terms of the permit, including information claimed to be confidential. Information claimed to be confidential must be accompanied by a claim of confidentiality according to the provisions of 40 CFR Part 2, Subpart B.

[40 CFR 71.6(a)(6)(v) and 40 CFR 71.5(a)(3)]

2. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information. In addition, a permittee shall provide additional information as necessary to address any requirements that become applicable after the date a complete application is filed, but prior to release of a draft permit.

[40 CFR 71.5(b)]

X.E. Submissions [40 CFR 71.5(d), 71.6(c)(1) and 71.9(h)(2)]

1. Any document (application form, report, compliance certification, etc.) required to be submitted under this permit shall be certified by a responsible official as to truth, accuracy, and completeness. Such certifications shall state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

[Explanatory note: The EPA has developed a reporting form "CTAC" for certifying truth, accuracy and completeness of Part 71 submissions. The form may be found on the EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

2. All fee calculation worksheets and applications for renewals and permit modifications shall be submitted to:

   Part 71 Permit Contact
   Air Program, 8P-AR
   U.S. Environmental Protection Agency,
   1595 Wynkoop Street
   Denver, Colorado 80202

3. Except where otherwise specified, all reports, test data, monitoring data, notifications, and compliance certifications shall be submitted to:

   Director
   Air Toxics and Technical Enforcement Program, 8ENF-AT
   U.S. Environmental Protection Agency,
   1595 Wynkoop Street
   Denver, Colorado 80202

X.F. Severability Clause [40 CFR 71.6(a)(5)]

The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any portion is held invalid, the remaining permit conditions shall remain valid and in force.

X.G. Permit Actions [40 CFR 71.6(a)(6)(iii)]

This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

X.H. Administrative Permit Amendments [40 CFR 71.7(d)]

1. The permittee may request the use of administrative permit amendment procedures for a permit revision that:

   (a) Corrects typographical errors;

   (b) Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source;

   (c) Requires more frequent monitoring or reporting by the permittee;

   (d) Allows for a change in ownership or operational control of a source where the EPA determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the EPA;

(e) Incorporates into the Part 71 permit the requirements from preconstruction review permits authorized under an EPA-approved program, provided that such a program meets procedural requirements substantially equivalent to the requirements of §§71.7 and 71.8 that would be applicable to the change if it were subject to review as a permit modification, and compliance requirements substantially equivalent to those contained in §71.6; or

(f) Incorporates any other type of change which the EPA has determined to be similar to those listed above in (a) through (e) above.

[Note to permittee: If (a) through (e) above do not apply, please contact the EPA for a determination of similarity prior to submitting your request for an administrative permit amendment under this provision.]

X.I. Minor Permit Modifications [40 CFR 71.7(e)(1)]

1. The permittee may request the use of minor permit modification procedures only for those modifications that:

   (a) Do not violate any applicable requirement;

   (b) Do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit;

   (c) Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

   (d) Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

      (i) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I; and
      (ii) An alternative emissions limit approved pursuant to regulations promulgated under Section 112(i)(5) of the Clean Air Act;

   (e) Are not modifications under any provision of Title I of the Clean Air Act; and

   (f) Are not required to be processed as a significant modification.

[40 CFR 71.7(e)(1)(i)(A)]

2. Notwithstanding the list of changes ineligible for minor permit modification procedures in (a) above, minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by the EPA.

[40 CFR 71.7(e)(1)(i)(B)]

3. An application requesting the use of minor permit modification procedures shall meet the requirements of §71.5(c) and shall include the following:

   (a) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

   (b) The source's suggested draft permit;

   (c) Certification by a responsible official, consistent with §71.5(d), that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used; and

   (d) Completed forms for the permitting authority to use to notify affected States as required under §71.8.

[40 CFR 71.7(e)(1)(ii)]

4. The source may make the change proposed in its minor permit modification application immediately after it files such application. After the source makes the change allowed by the preceding sentence, and until the permitting authority takes any of the actions authorized by §71.7(e)(1)(iv)(A) through (C), the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, the source need not comply with the existing permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

[40 CFR 71.7(e)(1)(v)]

5. The permit shield under §71.6(f) may not extend to minor permit modifications.

[40 CFR 71.7(e)(1)(vi)]

X.J. Group Processing of Minor Permit Modifications [40 CFR 71.7(e)(2)]

1. Group processing of modifications by the EPA may be used only for those permit modifications:

   (a) That meet the criteria for minor permit modification procedures under the Minor Permit Modifications section of this permit; and

(b) That collectively are below the threshold level of 10% of the emissions allowed by the permit for the emissions unit for which the change is requested, 20% of the applicable definition of major source in §71.2, or 5 tons per year, whichever is least.

[40 CFR 71.7(e)(2)(i)]

2. An application requesting the use of group processing procedures shall be submitted to the EPA, shall meet the requirements of §71.5(c), and shall include the following:

(a) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

(b) The source's suggested draft permit;

(c) Certification by a responsible official, consistent with §71.5(d), that the proposed modification meets the criteria for use of group processing procedures and a request that such procedures be used;

(d) A list of the source's other pending applications awaiting group processing, and a determination of whether the requested modification, aggregated with these other applications, equals or exceeds the threshold set under subparagraph (a) above; and

(e) Completed forms for the permitting authority to use to notify affected States as required under §71.8.

[40 CFR 71.7(e)(2)(ii)]

3. The source may make the change proposed in its minor permit modification application immediately after it files such application. After the source makes the change allowed by the preceding sentence, and until the permitting authority takes any of the actions authorized by §71.7(e)(1)(iv)(A) through (C), the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, the source need not comply with the existing permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

[40 CFR 71.7(e)(2)(v)]

4. The permit shield under §71.6(f) may not extend to group processing of minor permit modifications.

[40 CFR 71.7(e)(2)(vi)]

X.K. Significant Permit Modifications [40 CFR 71.7(e)(3)]

1. The permittee must request the use of significant permit modification procedures for those modifications that:

(d) Do not qualify as minor permit modifications or as administrative amendments;

(b) Are significant changes in existing monitoring permit terms or conditions; or

(c) Are relaxations of reporting or recordkeeping permit terms or conditions.

[40 CFR 71.7(e)(3)(i)]

2. Nothing herein shall be construed to preclude the permittee from making changes consistent with Part 71 that would render existing permit compliance terms and conditions irrelevant.

[40 CFR 71.7(e)(3)(i)]

3. Permittees must meet all requirements of Part 71 for applications, public participation, and review by affected states and tribes for significant permit modifications. For the application to be determined complete, the permittee must supply all information that is required by §71.5(c) for permit issuance and renewal, but only that information that is related to the proposed change.

[40 CFR 71.7(e)(3)(ii), 71.8(d), and 71.5(a)(2)]

X.L. Reopening for Cause [40 CFR 71.7(f)]

1. The permit may be reopened and revised prior to expiration under any of the following circumstances:

(a) Additional applicable requirements under the Act become applicable to a major Part 71 source with a remaining permit term of three (3) or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions have been extended pursuant to §71.7 (c)(3);

(b) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit;

(c) The EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or

(d) The EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

X.M. Property Rights [40 CFR 71.6(a)(6)(iv)]

This permit does not convey any property rights of any sort, or any exclusive privilege.

X.N. Inspection and Entry [40 CFR 71.6(c)(2)]

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the EPA or an authorized representative to perform the following:

1. Enter upon the permittee's premises where a Part 71 source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

4. As authorized by the Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

X.O. Emergency Provisions [40 CFR 71.6(g)]

1. In addition to any emergency or upset provision contained in any applicable requirement, the permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

    (a) An emergency occurred and that the permittee can identify the cause(s) of the emergency;

    (b) The permitted facility was at the time being properly operated;

    (c) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit; and

    (d) The permittee submitted notice of the emergency to the EPA within two (2) working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This notice fulfills the requirements for prompt notification of deviations.

2. In any enforcement proceeding the permittee attempting to establish the occurrence of an emergency has the burden of proof.

3. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

X.P. Transfer of Ownership or Operation [40 CFR 71.7(d)(1)(iv)]

A change in ownership or operational control of this facility may be treated as an administrative permit amendment if the EPA determines no other change in this permit is necessary and provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the EPA.

X.Q. Off Permit Changes [40 CFR 71.6(a)(12) and 40 CFR 71.6(a)(3)(ii)]

The permittee is allowed to make certain changes without a permit revision, provided that the following requirements are met, and that all records required by this section are kept for a period of 5 years:

1. Each change is not addressed or prohibited by this permit;

2. Each change shall meet with all applicable requirements and shall not violate any existing permit term or condition;

3. Changes under this provision may not include changes subject to any requirement of 40 CFR Parts 72 through 78 or modifications under any provision of Title I of the Clean Air Act;

4. The permittee must provide contemporaneous written notice to the EPA of each change, except for changes that qualify as insignificant activities under §71.5(c)(11). The written notice must describe each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change;

5. The permit shield does not apply to changes made under this provision; and

6. The permittee must keep a record describing all changes that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes.

7. For replacement of an existing permitted compressor engine with an engine of the same make, model, horsepower rating, and configured to operate in the same manner as the engine being replaced or for replacement of an existing permitted turbine with a new or overhauled turbine of the same make, model, MMBtu/hr, and configured to operate in the

same manner as the turbine being replaced, in addition to satisfying all other provisions for off permit changes, the permittee satisfies the following provisions:

(a) The replacement engine or turbine employs air emissions control devices, monitoring, record keeping and reporting that are equivalent to those employed by the engine or turbine being replaced;

(b) The replacement of the existing engine or turbine does not constitute a major modification or major new source as defined in Federal PSD regulations (40 CFR 52.21);

(c) No new applicable requirements, as defined in 40 CFR 71.2, are triggered by the replacement; and

(d) The following information is provided in a written notice to the EPA, in addition to the standard information listed above for contemporaneous written notices for off permit changes:

  (i) Make, model number, serial number, horsepower rating and configuration of the existing engine and the replacement engine;
  (ii) Make, model number, serial number MMBtu/hr and configuration of the permitted turbine and the replacement turbine;
  (iii) Manufacture date, commence construction date (per the definition in 40 CFR 60.2, 60.4230(a) and 63.2), and installation date of the replacement engine or turbine;
  (iv) If applicable, documentation of the cost to rebuild a replacement engine or turbine versus the cost to purchase a new engine or turbine in order to support claims that an engine is not “reconstructed,” as defined in 40 CFR 60.15 and 40 CFR 63.2;
  (v) 40 CFR Part 60, Subpart KKKK (New Turbine NSPS) non-applicability documentation as appropriate;
  (vi) 40 CFR Part 63, Subpart YYYY (Turbine MACT) non-applicability documentation as appropriate;
  (vii) 40 CFR Part 60, Subpart IIII (CI Engine NSPS) non-applicability documentation as appropriate;
  (viii) 40 CFR Part 60, Subpart JJJJ (SI Engine NSPS) non-applicability documentation as appropriate;
  (ix) 40 CFR Part 63, Subpart ZZZZ (RICE MACT) non-applicability documentation for <u>major</u> sources, as appropriate;
  (x) Documentation to demonstrate that the replacement does not constitute a major new source or major modification, as defined in Federal PSD rules (40 CFR 52.21), as follows:

    A. If the replacement will not constitute a "physical change or change in the method of operation" as described in §52.21(b)(2)(i), an explanation of how that conclusion was reached shall be provided.

B. If the replacement will constitute a "physical change or change in the method of operation" as described §52.21(b)(2)(i), the following information shall be provided:

(1) If the existing source is a "major stationary source" as defined in §52.21(b)(1): For each "regulated NSR pollutant" as defined in §52.21(b)(50), a demonstration (including all calculations) that the replacement will not be a "major modification" as defined in §52.21(b)(2). A modification is major only if it causes a "significant emissions increase" as defined in §52.21(b)(40), and also causes a "significant net emissions increase" as defined in §§52.21(b)(3) and (b)(23).

The procedures of §52.21(a)(2)(iv) shall be used to calculate whether or not there will be a significant emissions increase. If there will be a significant emissions increase, then calculations shall be provided to demonstrate there will not be a significant net emissions increase. These latter calculations shall include all sourcewide contemporaneous and creditable emission increases and decreases, as defined in §52.21(b)(3), summed with the PTE of the replacement unit(s).

If netting is used to demonstrate that the replacement will not constitute a "major modification," verification shall be provided that the replacement engine(s) or turbine(s) employ emission controls at least equivalent in control effectiveness to those employed by the engine(s) or turbine(s) being replaced.

PTE of replacement unit(s) shall be determined based on the definition of PTE in §52.21(b)(4). For each "regulated NSR pollutant" for which the PTE is not "significant," calculations used to reach that conclusion shall be provided.

(2) If the existing source is not a "major stationary source" as defined in §52.21(b)(1): For each "regulated NSR pollutant," a demonstration (including all calculations) that the replacement engine(s) or turbine(s), by itself, will not constitute a "major stationary source" as defined in §52.21(b)(1)(i).

8. The notice shall be kept on site and made available to the EPA on request, in accordance with the general recordkeeping provision of this permit.

9. Submittal of the written notice required above shall not constitute a waiver, exemption, or shield from applicability of any applicable standard or PSD permitting requirements under 40 CFR 52.21 that would be triggered by the replacement of any one engine or turbine, or by replacement of multiple engines or turbines.

X.R. Permit Expiration and Renewal [40 CFR 71.5(a)(1)(iii), 71.5(a)(2), 71.5(c)(5), 71.6(a)(11), 71.7(b), 71.7(c)(1), and 71.7(c)(3)]

1. This permit shall expire upon the earlier occurrence of the following events:

   (a) Five (5) years elapses from the date of issuance; or

   (b) The source is issued a Part 70 or Part 71 permit under an EPA approved or delegated permit program.

[40 CFR 71.6(a)(11)]

2. Expiration of this permit terminates the permittee's right to operate unless a timely and complete permit renewal application has been submitted at least six (6) months but not more than 18 months prior to the date of expiration of this permit.

[40 CFR 71.5(a)(1)(iii)]

3. If the permittee submits a timely and complete permit application for renewal, consistent with §71.5(a)(2), but EPA has failed to issue or deny the renewal permit, then all the terms and conditions of the permit, including any permit shield granted pursuant to §71.6(f) shall remain in effect until the renewal permit has been issued or denied.

[40 CFR 71.7(c)(3)]

4. The permittee's failure to have a Part 71 permit is not a violation of this part until EPA takes final action on the permit renewal application. This protection shall cease to apply if, subsequent to the completeness determination, the permittee fails to submit any additional information identified as being needed to process the application by the deadline specified in writing by EPA.

[40 CFR 71.7(b)]

5. Renewal of this permit is subject to the same procedural requirements that apply to initial permit issuance, including those for public participation, affected State, and tribal review.

[40 CFR 71.7(c)(1)]

6. The application for renewal shall include the current permit number, description of permit revisions and off permit changes that occurred during the permit term, any applicable requirements that were promulgated and not incorporated into the permit during the permit term, and other information required by the application form.

[40 CFR 71.5(a)(2) and 71.5(c)(5)]

XI. Appendix

XI.A. Inspection Information

1. Directions to Plant from Durango:

   From the Durango, Colorado Airport take Highway 172 west approximately 3 miles to County Road 307. Turn South on County Road 307 and drive for approximately 4 miles. The plant will be on the left.

2. Global Positioning System (GPS)

   Latitude 37^{o} 08.43' N
   Longitude -107^{o} 47.04' West

XI.B. CAM Plan

Attached

Appendix B – Compliance Assurance Monitoring (CAM) Plan

CAM Plan for West Glycol Dehydrator Regenerator Vent (Unit 15)

I. Background

A. Emissions Unit

Description: West Glycol Dehydrator (regenerator vent controlled by plant flare)
Identification: Unit ID 15
Facility: Ignacio Gas Plant, Durango, Colorado

B. Applicable Regulations & Emission Limits

Regulation: PSD Permit # PSD-SU-0027-01.00
Emission limits: 6.7 tpy of VOC (Permit Condition F.1.)

C. Control Technology & PTE

Controls: Open-tip Flare (Unit ID 23)
Potential pre-control device emissions: 584.7 tpy of VOC
Potential post-control device emissions: 6.7 tpy of VOC

II. Monitoring Approach

The key elements of the monitoring approach are presented in the attached table.

III. Response to Excursion

A. An excursion outside the indicator range signaling the improper operation of the flare will trigger an inspection, corrective action, recordkeeping, and reporting. Maintenance personnel will inspect the control device and indicator with 24 hours and make necessary repairs as soon as practicable.

B. Any number of excursions that exceed the Quality Improvement Plan (QIP) threshold shall trigger the requirement for a QIP for the associated indicator.

If the EPA determines that the permittee has not used acceptable procedures in response to excursions of the indicator, the EPA may require the permittee to prepare a QIP. The QIP will include procedures for evaluating the control performance problems and actions to correct the problems identified. Implementation of QIP shall not excuse the permittee from compliance with any emission limitation or standard, or any existing monitoring, testing, reporting, or recordkeeping requirement that may

apply under any federal, state, or local law, or any other applicable regulation under the Clean Air Act.

Monitoring Approach: Williams Ignacio Plant Flare for West Glycol Dehydrator Regenerator Vent (Unit ID 15)

		Indicator No. 1	Indicator No. 2
I. Indicator		Operate flare with presence of a pilot flame at all times.	Operate flare with no visible emissions.
Measurement Approach		Continuously measure the temperature of the pilot flame using a thermocouple or equivalent temperature sensing device equipped with a continuous recording device.	Continuously observe flare for visible emissions using a remote viewing system (camera with live video feed in plant control room). If any visible emissions are observed, operator shall immediately use Method 22 of 40 CFR Part 60, Appendix A to confirm visible emissions. The observation period shall be two (2) hours.
II. Indicator Range		An excursion is defined as any loss of flare flame. The pilot system is equipped with auto-ignition and automatically re-lights the pilot. Associated recordkeeping and reporting shall be conducted for each excursion event as required.	An excursion is defined as any visible emissions observed using Method 22 that continues for longer than five (5) minutes during the 2 hour observation period.
QIP Threshold		No more than six (6) excursions in any semiannual reporting period.	No more than 12 excursions in any semiannual reporting period.
III. Performance Criteria	A. Data Representativeness	The thermocouple will determine the presences or absence of a pilot flame. Requiring the presence of a pilot flame will assure ignition of the flare when waste gas is vented to it.	Observation of the flare in the plant control room via the remote viewing system will continuously monitor the control device for visible emissions. Requiring flare operation with no visible emissions will assure proper operation of the flare.
	B. Verification of Operational Status	With loss of pilot flame, observation of flare flame will be confirmed with the plant camera and remote viewing system.	The observation of visible emissions will indicate that he control device is malfunctioning.

		Indicator No. 1	Indicator No. 2
	C. QA / QC Practices / Criteria	The thermocouple, data recorder, malfunction alarm with notification system shall be inspected for proper operation on a quarterly basis.	The camera and video feed for the remote viewing system shall be inspected for proper operation on a quarterly basis. Records of the inspection shall be maintained at the facility.
	D. Monitoring Frequency	The presence of a pilot flame shall be monitored continuously.	The flare shall be continuously monitored with the remote viewing system.
	E. Data Collection Procedures	Pilot flame status is continuously monitored by the plant control room using alarm notification from the flare pilot system. The thermocouple shall be equipped with a continuous recording device such as a data logger or chart recorder to monitor proper thermocouple operation. Records of all inspection, maintenance, and repair activities shall be maintained on-site.	All visible emission events and Method 22 measurements shall be recorded in a log and maintained at the facility. The log shall include at a minimum, the date/time the event occurred, the duration of the event, the personnel that observed the event, and the corrective action taken.
	F. Averaging Time	Averaging is not necessary since the thermocouple will operate continuously.	None.

Justification

I. Background

This facility processes natural gas from the San Juan Basin gas gathering system. The West Glycol dehydrator uses a glycol solution to remove water from the plant inlet gas stream. The glycol functions in a continuous, closed-loop system, and is regenerated in a thermal reaction. This thermal reaction also removes any hydrocarbons that have been stripped away from the inlet gas stream. Hydrocarbon emissions from the West Dehydration Unit (Unit ID 15) are routed to the plant flare for the destruction of volatile organic compounds. The monitoring approach outlined here applies to the flare, which has a 98% destruction efficiency.

II. Rationale for Selection of Performance Indicators

The use of a thermocouple to detect the presence of pilot flame has been selected as a performance indicator because a continuous pilot flame is necessary to ensure waste gas combustion. The thermocouple monitors the temperature at the pilot flame of the flare. If the pilot flame goes out, the thermocouple detects the absence of the pilot flame and signals an alarm to the plant control room. The alarm triggers an investigation, relighting the pilot flame, and any necessary repairs that need to be made. The data logger associated with the thermocouple will provide continuous measurements for compliance assessment and recording the number of excursions.

Operating the flare with no visible emissions has been selected as a performance indicator because visible emissions indicate the flare is not functioning properly. The plant control room will monitor the flare continuously via a remote viewing system. If visible emissions are noted on the viewing monitor, Method 22 measurements will confirm the visible emissions to determine the remote viewing system is functioning properly. If visible emissions are observed, the permittee will inspect the control device and make any necessary repairs.

Regular inspections of the performance indicators will ensure the monitoring of proper control device operation.

III. Rationale for Selection of Indicator Ranges

The use of a thermocouple to detect the presence of a pilot flame was selected because the technique is already being employed by the permittee is an effective monitoring method for proper flare operation. The pilot flame is necessary to ensure combustion of the waste gas and achieve the desired 98% destruction efficiency. Once the absence of a pilot flame is detected, an alarm will trigger an inspection and repair. Quarterly inspections of the thermocouple system will be used for quality assurance purposes.

The performance indicator requiring flare operation with no visible emissions was selected because visible emissions indicate the flare is not functioning properly. The regulations at 40 CFR Part 60.18(b) provide the visible emission requirements that formed the basis for using this as a performance indicator. The flare is continuously observed in the plant control room via a camera and remote viewing monitoring. If the plant operator observes any visible emissions on the monitor, they will be confirmed with Method 22 readings. Any visible emissions will trigger an inspection and necessary repairs.

CAM Plan for East Glycol Dehydrator Regenerator Vent (Unit 16)

I. Background

A. Emissions Unit

Description: East Glycol Dehydrator (regenerator vent controlled by thermal oxidizer)
Identification: Unit ID 16
Facility: Ignacio Gas Plant, Durango, Colorado

B. Applicable Regulations & Emission Limits

Regulation: PSD Permit # PSD-SU-0027-01.00
Emission limits: 5.1 tpy of VOC when both Unit 16 and Unit 17 are operating (Permit Condition G.1.a.)

C. Control Technology & PTE

Controls: Thermal Oxidizer (Unit ID 22)
Potential pre-control device emissions: 107.7 tpy of VOC
Potential post-control device emissions: 5.1 tpy of VOC

II. Monitoring Approach

The key elements of the monitoring approach are presented in the attached table.

III. Response to Excursion

A. An excursion outside the indicator range signaling the improper operation of the thermal oxidizer will trigger an inspection, corrective action, recordkeeping, and reporting. Maintenance personnel will inspect the control device and indicator with 24 hours and make necessary repairs as soon as practicable.

B. Any number of excursions that exceed the Quality Improvement Plan (QIP) threshold shall trigger the requirement for a QIP for the associated indicator.

If the EPA determines that the permittee has not used acceptable procedures in response to excursions of the indicator, the EPA may require the permittee to prepare a QIP. The QIP will include procedures for evaluating the control performance problems and actions to correct the problems identified. Implementation of QIP shall not excuse the permittee from compliance with any emission limitation or standard, or any existing monitoring, testing, reporting, or recordkeeping requirement that may

apply under any federal, state, or local law, or any other applicable regulation under the Clean Air Act.

Monitoring Approach: Williams Ignacio Thermal Oxidizer for East Glycol Dehydrator Regenerator Vent (Unit ID 16)

	Indicator No. 1	**Indicator No. 2**	**Indicator No. 3**
I. Indicator	Operate thermal oxidizer combustion chamber above acceptable operating temperature while the east glycol dehydrator is operating.	Operate thermal oxidizer in a manner that achieves desired VOC destruction efficiency to meet emission limits.	Ensure no bypass of the thermal oxidizer is occurring.
Measurement Approach	Continuously measure the temperature of the combustion chamber using a thermocouple or equivalent temperature sensing device equipped with a continuous recording device.	Conduct annual stack test to determine the effectiveness of the thermal oxidizer in controlling VOC emissions.	Any bypass valve that would divert waste gas flow from the thermal oxidizer shall be maintained in a closed position.
II. Indicator Range	An excursion is defined as any detection of a temperature in the combustion chamber below 1,400°F when the dehydrator is operating. Any temperature detected below this temperature will trigger an alarm to the plant control room, an investigation to determine the problem, and to perform corrective action. Associated recordkeeping and reporting shall be conducted for each excursion event as required.	An excursion is defined as any detection of emissions above the permitted emission limit.	An excursion is defined as any occurrence in which the waste gas flow to the thermal oxidizer is diverted through a bypass line and vented to the atmosphere. The diversion of waste gas through a bypass valve to the atmosphere when necessary to maintain a safe work environment due to upset conditions is not considered an excursion for this indicator.
QIP Threshold	No more than six (6) excursions in any semiannual reporting period.	Any excursions in any annual reporting period.	No more than two (2) excursions in any semiannual reporting period.

		Indicator No. 1	Indicator No. 2	Indicator No. 3
III. Performance Criteria	A. Data Representativeness	The thermocouple will measure the temperature in the combustion chamber downstream of the combustion zone. The minimum accuracy of the thermocouple is ±5°F. Requiring the temperature of the combustion chamber above this temperature will ensure the system is operating correctly.	The stack test will determine the destruction efficiency achieved by the thermal oxidizer meets the permitted emission limits.	Monitoring to determine the bypass control valves for waste gas are maintained in a closed position will assure all the waste gas is routed to the control device.
	B. Verification of Operational Status	Not applicable.	Not applicable.	The observation of a waste gas bypass valve in open position and diverted waste gas away from the control device will indicate the control device is malfunctioning.
	C. QA / QC Practices / Criteria	The thermal oxidizer system has two (2) thermocouples for redundancy. The backup thermocouple will operate if the primary thermocouple detects a temperature outside the temperature range.	Annual stack test will validate the thermal oxidizer is effectively controlling VOC emissions. The inlet flow and outlet flow of the thermal oxidizer will be measured during the stack test to confirm the destruction efficiency.	All bypass valves which have the potential to divert waste gas away from the thermal oxidizer shall be visually inspected to confirm they are in a closed position on a weekly basis.
	D. Monitoring Frequency	The combustion chamber temperature shall be monitored continuously.	The performance test will be conducted annually.	All bypass valves shall be visually inspected on a weekly basis. A flow meter that detects waste gas flow in the bypass line or an electronic monitoring system with alarm notification will satisfy the visual inspection requirement.

		Indicator No. 1	Indicator No. 2	Indicator No. 3
	E. Data Collection Procedures	The thermocouple shall be equipped with a continuous recording device such as a data logger or chart recorder to monitor proper thermocouple operation. Records of all inspection, maintenance, and repair activities shall be maintained on-site.	Records of all performance test shall be provided to the EPA in an annual report.	A log shall be kept at the facility documenting all weekly inspections of bypass valves. Any excursion shall be documented in the log, along with the date/time of excursion, the personnel that performed the inspection, and the corrective action taken.
	F. Averaging Time	Averaging is not necessary since the thermocouple will operate continuously.	None.	None.

Justification

I. Background

This facility processes natural gas from the San Juan Basin gas gathering system. The East Glycol dehydrator uses a glycol solution to remove water from the plant inlet gas stream. The glycol functions in a continuous, closed-loop system, and is regenerated in a thermal reaction. This thermal reaction also removes any hydrocarbons that have been stripped away from the inlet gas stream. Hydrocarbon emissions from the East Dehydration Unit (Unit ID 16) are routed to thermal oxidizer for the destruction of volatile organic compounds.

The elevated combustion temperatures found in a thermal oxidizer are required to ensure sufficient destruction (98%+) of the VOCs while overcoming the flame-dampening characteristics found in a carbon dioxide (CO_2) -rich environment.

II. Rationale for Selection of Performance Indicators

The effectiveness of a thermal oxidizer in terms of waste gas destruction efficiency is usually linked to the operating temperature of the combustion chamber. The rate at which VOCs are oxidized is greatly affected by temperature. A higher operating temperature results in more of the waste gas oxidized to water and carbon dioxide. The combustion chamber operating temperature is used as a performance indicator to monitor the proper operation of the thermal oxidizer.

The destruction efficiency of the thermal oxidizer will be monitored by annual performance test. Performance test measuring the concentration of VOCs in the inlet and outlet flow of the waste gas stream will indicate proper operation of the control device.

Monitoring the status of bypass valves was selected as a performance indicator because bypass valves must be kept in a closed position so that all waste gas is being routed to the control device and not to the atmosphere.

Regular inspections of the performance indicators will ensure the monitoring of proper control device operation.

III. Rationale for Selection of Indicator Ranges

Since the waste gas stream temperature is generally much lower than that required for combustion, energy must be supplied to the incinerator to raise the waste gas temperature. The core of the thermal oxidizer is a nozzle-stabilized flame maintained by combustion of the auxiliary fuel, waste gas compounds, and supplemental air when necessary. Upon passing through the flame, the waste gas is heated from its inlet temperature to its ignition temperature. The ignition temperature is the temperature at which the combustion reaction rate exceeds the rate of heat losses, raising the temperature of the gases to some higher value. Thus, any organic/air mixture will ignite if its temperature is raised to a sufficiently high level. The organic-containing mixture ignites at a temperature between the preheat temperature and the reaction temperature. That is, ignition occurs at some point during the heating of the waste gas stream as it passes through the nozzle-stabilized flame regardless of its concentration. It is this ignition temperature that is monitored to ensure the sufficient destruction of VOCs.

If the annual performance test indicates the thermal oxidizer is not achieving the destruction efficiency required to meet the permitted emission limits, the permittee shall inspect the control device and make any necessary repairs to correct the problem. By demonstrating compliance with the permitted emission limits, the performance test indicates the control device is operating correctly.

Any detection of waste gas being diverted through a bypass valve away from the thermal oxidizer was selected because it would result in uncontrolled emissions to the atmosphere. All bypass valves should be maintained in a closed position to effectively route all waste gas to the control device.

CAM Plan for Amine Unit Regenerator Vent (Unit 17)

I. Background

A. Emissions Unit

Description: Amine Unit (regenerator vent controlled by thermal oxidizer)
Identification: Unit ID 17
Facility: Ignacio Gas Plant, Durango, Colorado

B. Applicable Regulations & Emission Limits

Regulation: PSD Permit # PSD-SU-0027-01.00
Emission limits: 5.1 tpy of VOC when both Unit 16 and Unit 17 are operating (Permit Condition G.1.a.)

C. Control Technology & PTE

Controls: Thermal Oxidizer (Unit ID 22)
Potential pre-control device emissions: 296.0 tpy of VOC
Potential post-control device emissions: 3.0 tpy of VOC

II. Monitoring Approach

The key elements of the monitoring approach are presented in the attached table.

III. Response to Excursion

A. An excursion outside the indicator range signaling the improper operation of the thermal oxidizer will trigger an inspection, corrective action, recordkeeping, and reporting. Maintenance personnel will inspect the control device and indicator with 24 hours and make necessary repairs as soon as practicable.

B. Any number of excursions that exceed the Quality Improvement Plan (QIP) threshold shall trigger the requirement for a QIP for the associated indicator.

If the EPA determines that the permittee has not used acceptable procedures in response to excursions of the indicator, the EPA may require the permittee to prepare a QIP. The QIP will include procedures for evaluating the control performance problems and actions to correct the problems identified. Implementation of QIP shall not excuse the permittee from compliance with any emission limitation or standard, or any existing monitoring, testing, reporting, or recordkeeping requirement that may

apply under any federal, state, or local law, or any other applicable regulation under the Clean Air Act.

Monitoring Approach: Williams Ignacio Thermal Oxidizer for Amine Unit Regenerator Vent (Unit ID 17)

	Indicator No. 1	Indicator No. 2	Indicator No. 3
I. Indicator	Operate thermal oxidizer combustion chamber above acceptable operating temperature when the amine unit is operating.	Operate thermal oxidizer in a manner that achieves desired VOC destruction efficiency to meet emission limits.	Ensure no bypass of the thermal oxidizer is occurring.
Measurement Approach	Continuously measure the temperature of the combustion chamber using a thermocouple or equivalent temperature sensing device equipped with a continuous recording device.	Conduct annual stack test to determine the effectiveness of the thermal oxidizer in controlling VOC emissions.	Any bypass valve that would divert waste gas flow from the thermal oxidizer shall be maintained in a closed position.
II. Indicator Range	An excursion is defined as any detection of a temperature in the combustion chamber below 1,400°F when the amine system is operating. Any temperature detected below this temperature will trigger an alarm to the plant control room, an investigation to determine the problem, and to perform corrective action. Associated recordkeeping and reporting shall be conducted for each excursion event as required.	An excursion is defined as any detection of emissions above the permitted emission limit.	An excursion is defined as any occurrence in which the waste gas flow to the thermal oxidizer is diverted through a bypass line and vented to the atmosphere. The diversion of waste gas through a bypass valve to the atmosphere when necessary to maintain a safe work environment due to upset conditions is not considered an excursion for this indicator.
QIP Threshold	No more than six (6) excursions in any semiannual reporting period.	Any excursions in any annual reporting period.	No more than two (2) excursions in any semiannual reporting period.

		Indicator No. 1	Indicator No. 2	Indicator No. 3
III. Performance Criteria	A. Data Representativeness	The stack test will determine the destruction efficiency achieved by the thermal oxidizer meets the permitted emission limits.	The stack test will determine the destruction efficiency achieved by the thermal oxidizer meets the permitted emission limits.	Monitoring to determine the bypass control valves for waste gas are maintained in a closed position will assure all the waste gas is routed to the control device.
	B. Verification of Operational Status	Not applicable.	Not applicable.	The observation of a waste gas bypass valve in open position and diverted waste gas away from the control device will indicate the control device is malfunctioning.
	C. QA / QC Practices / Criteria	Annual stack test will validate the thermal oxidizer is effectively controlling VOC emissions. The inlet flow and outlet flow of the thermal oxidizer will be measured during the stack test to confirm the destruction efficiency.	Annual stack test will validate the thermal oxidizer is effectively controlling VOC emissions. The inlet flow and outlet flow of the thermal oxidizer will be measured during the stack test to confirm the destruction efficiency.	All bypass valves which have the potential to divert waste gas away from the thermal oxidizer shall be visually inspected to confirm they are in a closed position on a weekly basis.
	D. Monitoring Frequency	The performance test will be conducted annually.	The performance test will be conducted annually.	All bypass valves shall be visually inspected on a weekly basis. A flow meter that detects waste gas flow in the bypass line or an electronic monitoring system with alarm notification will satisfy the visual inspection requirement.

		Indicator No. 1	Indicator No. 2	Indicator No. 3
	E. Data Collection Procedures	Records of all performance test shall be provided to the EPA in an annual report.	Records of all performance test shall be provided to the EPA in an annual report.	A log shall be kept at the facility documenting all weekly inspections of bypass valves. Any excursion shall be documented in the log, along with the date/time of excursion, the personnel that performed the inspection, and the corrective action taken.
	F. Averaging Time	None.	None.	None.

Justification

I. Background

This facility processes natural gas from the San Juan Basin gas gathering system. Amine treatment systems are often used at natural gas processing facilities to remove acid gases such as hydrogen sulfide and CO_2 from natural gas streams. The two main processes within an amine unit are absorption and regeneration. A natural gas inlet stream containing acid gases is introduced into an absorption column where the inlet stream is counter-currently contacted with an amine solution. The amine solution absorbs the acid gases, and to some extent small quantities of hydrocarbons in the inlet stream. After the absorption process, the rich amine must be regenerated before it can be reused. The rich amine is sent to a regeneration column to strip the absorbed gas from the amine. These regeneration processes result in acid gases and hydrocarbons released to the atmosphere. Rather than venting the hydrocarbons and acid gases to the atmosphere, a thermal oxidizer is used to control these emissions. The elevated combustion temperatures found in a thermal oxidizer are required to ensure sufficient destruction (98%+) of the VOCs while overcoming the flame-dampening characteristics found in a CO_2-rich environment.

II. Rationale for Selection of Performance Indicators

The effectiveness of a thermal oxidizer in terms of waste gas destruction efficiency is usually linked to the operating temperature of the combustion chamber. The rate at which VOCs are oxidized is greatly affected by temperature. A higher operating temperature results in more of the waste gas oxidized to water and carbon dioxide. The combustion chamber operating temperature is used as a performance indicator to monitor the proper operation of the thermal oxidizer.

The destruction efficiency of the thermal oxidizer will be monitored by annual performance test. Performance test measuring the concentration of VOCs in the inlet and outlet flow of the waste gas stream will indicate proper operation of the control device.

Monitoring the status of bypass valves was selected as a performance indicator because bypass valves must be kept in a closed position so that all waste gas is being routed to the control device and not to the atmosphere.

Regular inspections of the performance indicators will ensure the monitoring of proper control device operation.

III. Rationale for Selection of Indicator Ranges

Since the waste gas stream temperature is generally much lower than that required for combustion, energy must be supplied to the incinerator to raise the waste gas temperature. The core of the thermal oxidizer is a nozzle-stabilized flame maintained by combustion of the auxiliary fuel, waste gas compounds, and supplemental air when necessary. Upon passing through the flame, the waste gas is heated from its inlet temperature to its ignition temperature. The ignition temperature is the temperature at which the combustion reaction rate exceeds the rate of heat losses, raising the temperature of the gases to some higher value. Thus, any organic/air mixture will ignite if its temperature is raised to a sufficiently high level. The organic-containing mixture ignites at a temperature between the preheat temperature and the reaction temperature. That is, ignition occurs at some point during the heating of the waste gas stream as it passes through the nozzle-stabilized flame regardless of its concentration. It is this ignition temperature that is monitored to ensure the sufficient destruction of VOCs.

If the annual performance test indicates the thermal oxidizer is not achieving the destruction efficiency required by the permit, the permittee shall inspect the control device and make any necessary repairs to correct the problem. By demonstrating compliance with the permitted emission limits, the performance test indicates the control device is operating correctly.

Any detection of waste gas being diverted through a bypass valve away from the thermal oxidizer was selected because it would result in uncontrolled emissions to the atmosphere. All bypass valves should be maintained in a closed position to effectively route all waste gas to the control device.