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

BP America Production Company
Florida River Compression Facility

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(s):

Southern Ute Indian Reservation
SE ¼ , SW ¼ of Section 25, Township 34N, Range 9W
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.

Callie A.Videtich, Director Air Program US EPA Region 8	CCT 18 2010 Date

THIS PAGE INTENTIONALLY LEFT BLANK

AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE

BP America Production Company
Florida River Compression Facility

Permit Number: V-SU-0022-05.00
Replaces Amended Permit No.: V-SU-0022-00.04

Issue Date: October 18, 2010
Effective Date: November 27, 2010
Expiration Date: November 27, 2015

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

Permit Revision History

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION
June 2001	Initial Permit Issued		Permit # V-SU-0022-00.00 (revised 4 times)
October 2010	1st Renewal Issued		Permit # V-SU-0022-05.00

TABLE OF CONTENTS

Abbreviations and Acronyms iii
LIST OF TABLES iv
I. Source Information and Emission Unit Identification 1
- **A. General Source Information** 1
- **B. Source Emission Points** 3

II. Requirements for Turbines 5
- **A. 40 CFR Part 60, Subpart A – New Source Performance Standards, General Provisions** 5
- **B. 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Combustion Turbines** 5
- **C. Emission Standards and Limits** 5
- **D. Monitoring Requirements** 6
- **E. Recordkeeping Requirements** 8

III. Requested NO_x Emission CAP for Electric Generator Engine Project 10
- **A. Emission Standards and Limits** 10
- **B. Work Practice and Operational Requirements** 10
- **C. Testing Requirements** 12
- **D. Monitoring Requirements** 13
- **E. Recordkeeping Requirements** 13
- **F. Reporting Requirements** 15

IV. Facility-Wide Requirements 16
- **A. General Recordkeeping Requirements** 16
- **B. General Reporting Requirements** 16
- **C. Chemical Accident Prevention** 18
- **D. Alternative Operating Scenarios - Turbine Replacement/Overhaul** 18
- **E. Alternative Operating Scenario – Diesel Fired Electric Generating Unit Replacement/Overhaul** 19
- **F. Permit Shield** 19

V. Part 71 Administrative Requirements 20
- **A. Annual Fee Payment** 20
- **B. Annual Emissions Inventory** 22
- **C. Compliance Requirements** 22
- **D. Duty to Provide and Supplement Information** 24
- **E. Submissions** 24
- **F. Severability Clause** 25
- **G. Permit Actions** 25
- **H. Administrative Permit Amendments** 25
- **I. Minor Permit Modifications** 26
- **J. Group Processing of Minor Permit Modifications** 27
- **K. Significant Permit Modifications** 28
- **L. Reopening for Cause** 29
- **M. Property Rights** 29
- **N. Inspection and Entry** 29
- **O. Emergency Provisions** 29
- **P. Transfer of Ownership or Operation** 30
- **Q. Off Permit Changes** 30
- **R. Permit Expiration and Renewal** 34

VI. Appendix **36**
A. Inspection Information **36**
B. Custom Fuel Monitoring Schedule and Approval **36**
C. Portable Analyzer Monitoring Protocol and Approval **36**

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 and diluent monitoring)
COMS	Continuous Opacity Monitoring System
CO	Carbon monoxide
CO2	Carbon dioxide
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
gal	gallon
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
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

LIST OF TABLES

Table 1. Source Emission Points……………………………………………………...………3
Table 2. Insignificant Emission Points…………………………………………………………..4
Table 3. Turbine Emission Limits……………………………………………………………....5

I. Source Information and Emission Unit Identification

I.A. General Source Information

Parent Company name: BP America Production Company

Plant Name: Florida River Compression Facility

Plant Location: SE 1/4, SW1/4 of Section 25, T34N, R9W
Latitude 37-09-23.0 Longitude -107-46-50.0

Region: 8 **State:** Colorado **County:** La Plata

Reservation: Southern Ute Reservation **Tribe:** Southern Ute Indian Tribe

Responsible Official: Florida Operations Manager

Alternate Responsible Official: Durango Operations Manager

SIC Code: 1311

AFS Plant Identification Number: 08-067-00034

Other Clean Air Act Permits: This is the first renewal of the Part 71 permit. There are no other permits, such as PSD or minor NSR, issued to this facility.

Description of Process:

The Florida River Compression Facility processes coal bed methane gas in order to reduce CO_2 and water content to within pipeline specifications and compresses this gas for delivery into interstate pipelines. The plant has four medium pressure gas inlets (Area 6, ECBM, MPP, Red Cedar) and two low pressure gas inlets (Area 1 East, Area West). Current plant throughput averages around 380 million standard cubic feet per day (MMscfd) with plant process capacity around 400 MMscfd. Low pressure gas (about 105 MMscfd) enters the plant through an inlet separator to remove free liquids after which it is compressed from 50 to 300 psig. Initial compression of low pressure gas is done by two electric driven, ammonia refrigerated screw compressors and two electric driven reciprocating compressors.

About 20 MMscfd of the low pressure gas is then commingled with medium pressure gas and treated by methyl-di-ethanol-amine (MDEA) sweetening to remove CO_2, followed by triethylene glycol (TEG) dehydration to remove water vapor from the gas. The low pressure gas bypassing amine mixes with amine treated gas in the dehydration header such that all gas is blended and identical going to the three dehydrators. The CO_2 and water vapor are vented to the atmosphere. The gas is then compressed to 800 psig and sent to El Paso, Transwestern or Northwest Pipeline for transport to market via interstate pipeline.

Gas from Area 6, ECBM and Red Cedar (about 75 MMscfd) enters the plant at 300 psig, goes directly to the treating processes and is then compressed to 800 psig and sent to market. Gas from the medium pressure pipeline enters the plant already low in CO_2 and previously dried at upstream compression. It is commingled with the processed gas and compressed for transport via pipeline.

The treating processes include two MDEA trains to remove CO_2 and three (TEG) dehydration units. Gas fired heaters are utilized to heat ethylene glycol (EG) which is used as the heat medium to generate lean MDEA from CO_2 saturated (rich) MDEA and for heating some tanks in the plant. The dehydrators are fired on natural gas to evaporate water from rich TEG. Post treatment compression consists of three electric driven centrifugal compressors, two “temporary” electric driven reciprocating compressors and two natural gas fired Solar Centaur turbine driven centrifugal compressors.

The plant is equipped with a ground flare “candle” system to combust gases that for various reasons cannot be sent to market. The flare system disposes of a minimum of about 100,000 scfd, but is designed to handle the full inlet for a very brief time in an emergency or plant upset situations.

Twelve 2,922 hp diesel fired generator sets were installed at the plant in 2004 for the purpose of reducing plant electric load during times of monthly peak electrical grid load; which has the effect of significantly reducing the plant’s electrical bill. Due to the infrequency of use combined with use of selective catalytic reduction for NO_x control, the emissions impact from these generators is minimal.

Current pigging operations include four receivers with varying diameters: two 16 inch, two 12 inch, one 10 inch, and one 8 inch, each about 6 feet long and operated at about 50 psi. Pigging operations occur once per month on average, totaling about 322 cubic feet at 50 psi.

I.B. Source Emission Points

Table 1 - Source Emission Points
BP Florida River Compression Facility

Emission Unit Id. No.	Description	Control Equipment
T-1	45 MMBtu/hr Solar Centaur H T5500 Turbine. Natural gas fired, simple cycle: Serial Number: HC90781 Installed: 1995	None
T-2	45 MMBtu/hr Solar Centaur H T5700 Turbine. Natural gas fired, simple cycle: Serial Number: HC93D50 Installed: 08/1999	None
AH-1	44.5 mmBtu/hr Amine Heater #1. Natural gas fired: Serial Number: 421 Installed: 1990 (Const. 5/30/1989)	None
AH-2	44.0 mmBtu/hr Amine Heater #2. Natural gas fired: Serial Number: 2440 Installed: 1997 (Const. 1980)	None
AV-1	70 MMscfd Amine Unit #1 Still Vent: Serial Number: NA Installed: 1990	None
Plant Flare	4 MMBtu/hr pilot, 0.1 – 400 MMscfd; 98% VOC control efficiency Disposes of a minimum of 100,000 scf/d. Designed to handle full inlet for brief periods in emergency or plant upset situations VECO Custom Ground Flare Installed: 1/2004	None
	2922 hp Cummins QSK60; Diesel-fired electric generation unit:	Selective Catalytic Reduction (90% NO_x Reduction)
P-1	Serial Number: 33149137 Installed: 4/2004	
P-2	Serial Number: 33149295 Installed: 4/2004	
P-3	Serial Number: 33148889 Installed: 4/2004	
P-4	Serial Number: 33149128 Installed: 4/2004	
P-5	Serial Number: J000160545 Installed: 4/2004	
P-6	Serial Number: K000176265 Installed: 4/2004	
P-7	Serial Number: K000172343 Installed: 4/2004	
P-8	Serial Number: 1000155267 Installed: 4/2004	
P-9	Serial Number: 1000155269 Installed: 4/2004	
P-10	Serial Number: 1000148783 Installed: 4/2004	
P-11	Serial Number: L000190130 Installed: 4/2004	
P-12	Serial Number: K000172346 Installed: 4/2004	

Table 2 - Insignificant Emission Units
BP Florida River Compression Facility

Description
1 – 99 hp Emergency Diesel Generator (DMT Corporation, Model DMT-80C. Serial No. 89411-2)
1 -70 MMscfd Amine Unit #2 Vent
1 -Amine #2 Flash Tank
1 -2.5 MMBTU/hr Dehy Reboiler #1a
1 -2.5 MMBTU/hr Dehy Reboiler #1b
1 -2.5 MMBTU/hr Dehy Reboiler #2
1 -2.14 MMBTU/hr Dehy Reboiler #3a
1 -2.14 MMBTU/hr Dehy Reboiler #3b
1 - Dehy #1 Flash Tank
1 - Dehy #2 Flash Tank
1 - Dehy #3 Flash Tank
1 - 90 MMscfd Glycol Still Column Vent #1
1 - 35 MMscfd Glycol Still Column Vent #2
1 - 180 MMscfd Glycol Still Column Vent #3
Process Fugitive Emissions
1 - 1,000 gal Gasoline Tank
1 - 250 bbl MDEA Tank
1 - 300 bbl EG Tank
1 - 1,500 gal EG Tank
1 - 100 bbl TEG Tank
1 - 12,000 gal Diesel Fuel Tank
1 - 100 gal Diesel Fuel Tank
2 - 300 gal Diesel Tanks
4 - 2,400 gal Peaker Diesel Fuel Tanks
8 - 3,200 gal Peaker Diesel Fuel Tanks
1 - 300 bbl Waste Oil Tank
1 - 210 bbl Lube Oil Tank
1 - 100 bbl Oily Water Tank
3 - 550 gal Lube Oil Tanks
4 - 500 gal Lube Oil Tanks
1 - 238 gal Compressor Lube Oil Drain and Sump
6 - 55 gal Lube Oil Tanks

II. Requirements for Turbines

II.A. <u>40 CFR Part 60, Subpart A – New Source Performance Standards, General Provisions</u> [40 CFR Part 60, Subpart A]

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.

II.B. <u>40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Combustion Turbines</u> [40 CFR 60.330 – 60.335]

1. **Applicability** [40 CFR 60.330]

   (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:

   T-1: Natural gas-fired simple cycle turbine with a heat input capacity of 45 MMBtu/hr.
   T-2: Natural gas-fired simple cycle turbine with a heat input capacity of 45 MMBtu/hr.

II.C. <u>Emission Standards and Limits</u> [40 CFR 60.332 and 60.333; 40 CFR 71.6(a)(1), 71.6(a)(1)(i), and 71.6(a)(1)(iii)]

1. Emission units T-1 and T-2 are subject to the NO_x standard and the sulfur dioxide (SO_2) fuel standard listed in Table 3 below.

Table 3 - Turbine Emission Standards

Pollutant	Emission Standard	Regulatory Reference
NO_x	$STD = 0.0150\frac{(14.4)}{Y} + F = 174$ ppm where Y= 12.4 kilojoules per watt hour (manufacturer's rated heat rate at manufacturer's rated peak load) and F = 0 (NO_x emission allowance for fuel bound nitrogen) and STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis)	40 CFR 60.332(a)(2)
SO_2	Fuel sulfur content shall not exceed 0.8 percent by weight	40 CFR 60.333(b)

II.D. Monitoring Requirements [40 CFR 60.334 and 40 CFR 71.6(a)(3)(i)(A) through (C)]

1. The permittee shall measure NO_x emissions from emission units T-1 and T-2 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 a monitoring protocol approved by EPA. Such monitoring shall begin in the first calendar quarter following EPA notification to the applicant of the approval of the monitoring protocol. EPA approved the monitoring protocol in a May 6, 2002 letter (see Appendix C).

2. The permittee shall comply with the requirements of 40 CFR 60.334(b)(2) for monitoring of sulfur content and nitrogen content of the fuel being burned in units T-1 and T-2. For sulfur dioxide and nitrogen oxides, the custom fuel monitoring schedule as approved by the U.S. Environmental Protection Agency (EPA) Region 8 in a letter dated December 2, 1996 (see Appendix B), and listed below, shall be followed.

   (a) Fuel Nitrogen Monitoring Protocol.

      (i) Monitoring of fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine.

      (ii) Monitoring of fuel nitrogen content shall be determined 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).

      (iii) Should a nitrogen analysis, required for any reason other than firing an emergency fuel, demonstrate noncompliance with the emission standard for NO_x contained in 40 CFR 60.332, the permittee shall immediately notify EPA Region 8 of the excess emissions and nitrogen monitoring shall be conducted daily during the interim period while the custom fuel monitoring schedule is being re-examined by EPA Region 8.

   (b) Fuel Sulfur Monitoring Protocol.

   Analysis for fuel sulfur content of the natural gas shall be conducted using the appropriate methods specified in 40 CFR 60.335(d); or for Phase I sampling the permittee's GC monitoring system may be used; and under Phase II and III, the "length of stain tube" method is approved as an alternative fuel sulfur test method, providing that the Gas Processors Association procedures (GPA Standard 2377-86) are followed and 100% pipeline quality natural gas is the only fuel fired in the gas turbines.

      (i) The sampling and analysis frequency of fuel sulfur allowed under the custom fuel monitoring schedule is as follows:

Phase	Frequency	Technique	Period
I	Daily	El Paso GC data	Six months
II	Quarterly	Length of stain tube	Eighteen months
III	Semi-annually	Length of stain tube	Two years

(ii) If, during the period of each phase, the monitoring required above shows little variability in the fuel sulfur content and demonstrates compliance with the emission limits for SO_2 contained in 40 CFR 60.333, the permittee may then proceed to the next sampling phase with written notice to EPA Region 8.

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

(iv) Should a sulfur analysis, required for any reason other than for firing emergency fuel, demonstrate noncompliance with the emission standard for SO_2 contained in 40 CFR 60.333, the permittee shall immediately notify EPA Region 8 of the excess emissions and sulfur monitoring shall be conducted daily during the interim period while the custom fuel monitoring schedule is being re-examined by EPA Region 8.

3. After the initial four year term of the custom fuel monitoring schedule, the permittee will continue using the same monitoring requirements as stipulated in Phase III of the schedule in item (b)(i) above. EPA Region 8 may choose to terminate the custom fuel monitoring schedule and require the permittee to reapply for a custom fuel monitoring schedule. Termination of the custom fuel monitoring schedule will require that the permittee begin monitoring as required by 40 CFR 60.334.

4. If there is a change in fuel supply, the permittee must immediately notify EPA Region 8 of such change for re-examination of this custom fuel monitoring schedule. A change in fuel quality, fuel makeup or fuel supplier shall be considered as a change in fuel supply. Sulfur and nitrogen monitoring shall be conducted daily during the interim period when this custom fuel monitoring schedule is being re-examined.

5. All analyses required by this custom fuel monitoring schedule shall be performed by a laboratory using the approved test methods, except for Phase I testing using the permittee's GC and Phases II and III using the length of stain tube. The permittee may request that EPA Region 8 allow for the substitution of any analytical method for another method specified in this custom fuel monitoring schedule. Any substitution will require the written approval of EPA Region 8.

6. EPA Region 8 may request that an audit of the fuel sampling program be conducted at any time during the life of this custom fuel monitoring schedule. This audit shall consist of daily sampling of fuel gas for either nitrogen content, sulfur content, or both. The length of this audit shall be no less than two weeks. If noncompliance values are found, Section II.D.2(a)(iii) of this permit shall govern nitrogen content monitoring and Section II.D.2(b)(iv) of this permit shall govern sulfur content monitoring.

II.E. Recordkeeping Requirements [40 CFR 71.6(a)(3)(ii), 40 CFR 60.7(b) and 60.7(f), and custom fuel monitoring schedule as approved by EPA in a letter dated December 2, 1996 (see Appendix B)]

The permittee shall comply with the following recordkeeping requirements for turbine units T-1 and T-2:

1. 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.

2. The permittee shall maintain a file of all measurements, including performance testing measurements, monitoring device calibration checks, and other information required by the NSPS.

3. The permittee shall keep records of all required monitoring in Section II.D this permit. 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 comply with the following recordkeeping requirements when firing an emergency fuel in turbine units T-1 and T-2:

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

   (b) For turbines T-1 and T-2, monitoring of fuel nitrogen content shall be recorded daily while firing a fuel other than pipeline-quality natural gas.

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

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. 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 60.774(d)(1)]

III. Requested NO_x Emission CAP for Electric Generator Engine Project

The following requirements have been created, at the permittee's request, to establish enforceable limits of nitrogen oxide (NO_x) emissions to below PSD significant levels for a project to install electric generating units.

[CAA 304(f)(4), 40 CFR 71.6(b) and 71.7(e)(1)(i)(A)(4)(i)]

III.A. <u>Emission and Operating Limits</u>

1. P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, Cumulative NO_x emissions for the 12 diesel fired electric generating units [Units P-1, P-2, and P-12] shall not exceed 39.1 tons during any consecutive 12 months.

2. Cumulative hours of operation for all 12 diesel fired electric generating units shall not exceed 12,900 hours per year during any consecutive 12 months. The cumulative hours of start-ups for all 12 generating units shall not exceed 3000 hours per year during any consecutive 12 months.

3. Each electric generating unit is considered in shutdown mode if the unit runs less than 30 minutes per quarter.

   [Explanatory Note: The 30 minute run time per quarter per unit is necessary to ensure mechanical integrity while the units are in shut-down mode.]

   (a) During shutdown mode, run time records will be maintained and will be counted towards the allowable start hours.

   (b) The following conditions will continue to apply to units in shut-down mode:

      i. Section III.B.12 – Fuel sulfur content limit.
      ii. Section III.E.1, III.E.3, III.E.4(a), (b), and (c) – Record keeping requirements and calculation of rolling 12-month emissions.

   (c) The permittee shall notify EPA when the status of a unit changes to or from shut-down mode.

   (d) The permittee shall conduct a performance test, as specified in III.C, when a unit is taken out of shut-down mode or operates for 30 minutes or more per quarter.

III.B. <u>Work Practice and Operational Requirements</u>

1. The 12 Cummins QSK60 diesel fired electric generating units [Units P-1, P-2, P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, and P-12] shall each be equipped with a selective catalytic reduction (SCR) system for the control of NO_x.

2. The permittee shall follow, for each electric generating unit and associated SCR system, the manufacturer's recommended maintenance schedule and procedures to ensure optimum performance of each unit and control system.

3. Each electric generating unit shall have a dedicated ammonia injection system.

4. The permittee shall install temperature-sensing devices before the SCR systems on the electric generating units [Units P-1, P-2, P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, and P-12] in order to monitor the inlet temperature of the SCR for each generating unit. Each temperature-sensing device shall be accurate to within 0.75% of span.

5. The inlet temperature to each SCR shall be maintained at all times an electric generating unit operates at no less than 500 °F and no more than 1200 °F.

6. The inlet temperature to the SCR system shall be measured at least hourly during the operation of each electric generating unit.

7. If the inlet temperature to the SCR on any electric generating unit deviates from the acceptable range listed for each electric generating unit in Section III.B.5 above, then the following actions shall be taken:

   (a) Immediately upon determining a deviation of the SCR inlet temperature, the cause will be investigated. Investigation may include monitoring of NO_x emissions to ensure the SCR system is functioning and testing the temperature sensing device. If the cause is determined to be the SCR system, then the catalyst shall be inspected and cleaned or replaced, if necessary.

   (b) If the problem can be corrected by following the electric generating unit and/or the SCR manufacturer's recommended procedures, then the permittee shall correct the problem within 24 hours of inspecting the electric generating unit and SCR.

   (c) If the problem can not be corrected using the manufacturer's recommended procedures, then the affected electric generating unit shall not be returned to operation until the SCR inlet temperature is measured and found to be within the acceptable temperature range for that electric generating unit. The permittee shall also notify EPA in writing of the problem within 10 working days of observing the problem and include in the notification the cause of the problem and a corrective action plan that outlines the steps and timeframe for bringing the SCR inlet temperature range into compliance. (The corrective action may include removal and cleaning of the catalyst according to the manufacturer's methods or replacement of the catalyst.)

8. The pressure drop across an SCR system shall be measured at least hourly during the operation of each electric generating unit.

9. During operation the pressure drop across the SCR system on each of the electric generating units shall be maintained to within four (4) inches of water from the baseline pressure drop reading taken during the initial performance test.

10. If the pressure drop exceeds four (4) inches of water from the baseline pressure drop reading taken during the initial performance test, the cause will be investigated. Investigation may include monitoring of NO_x emissions to ensure the SCR system is functioning and testing the pressure transducers. If the cause is determined to be the SCR system, then the catalyst shall be inspected and cleaned or replaced, if necessary.

11. The permittee's completion of any or all of the actions prescribed by conditions III.B.7 and III.B.10 of this permit shall not constitute, nor qualify as, an exemption from the NO_x emission limit in this permit.

12. The maximum sulfur content of the diesel fuel fired in the electric generating units shall not exceed 0.5 percent.

III.C. <u>Testing Requirements</u>

1. An initial performance test shall be conducted for each of the 12 diesel fired electric generating units [Units P-1, P-2, P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, and P-12] for measuring NO_x emissions to demonstrate compliance with the cumulative emission limit in Section III.A.1. The initial performance test for NO_x for each unit shall be conducted within forty-five (45) calendar days of initial startup of the diesel fired electric generating units.

2. Upon change out of any one of the 12 diesel fired electric generating units [Units P-1, P-2, P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, and P-12], a performance test shall be conducted for measuring NO_x emissions from the unit to demonstrate compliance cumulative emission limit in Section III.A.1. The performance test for NO_x for each unit shall be conducted within forty-five (45) calendar days of initial startup of the diesel fired electric generating units.

3. The performance tests for NO_x shall be conducted in accordance with the test methods specified in 40 CFR Part 60, Appendix A.

4. The inlet temperature to the SCR and the pressure drop across the SCR system shall both be measured for each electric generating unit during the performance test for measuring NO_x emissions.

5. All tests for NO_x emissions for the diesel fired electric generating units must meet the following requirements:

    (a) All tests shall be performed at a maximum operating rate (90% to 110% of engine design capacity).

    (b) During each test run, data shall be collected on all parameters necessary to document how NO_x emissions in pounds per hour were measured or calculated (such as test run length, minimum sample volume, volumetric flow rate, moisture and oxygen corrections, etc.).

(c) Each source test shall consist of at least three (3) 1-hour or longer valid test runs. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of lbs/hr and tons/year.

(d) A source test plan for NO_x emissions shall be submitted to EPA for approval within thirty (30) calendar days of the effective date of this permit. The source test plan shall include and address the following elements:

(i) Purpose of the test;
(ii) Generating units and associated SCR systems to be tested;
(iii) Expected engine operating rate(s) during test;
(iv) Schedule/dates for test;
(v) Sampling and analysis procedures (sampling locations, test methods, laboratory identification);
(vi) Quality assurance plan (calibration procedures and frequency, sample recovery and field documentation, chain of custody procedures); and
(vii) Data processing and reporting (description of data handling and quality control procedures, report content).

III.D. <u>Monitoring Requirements</u>

1. The permittee shall measure NO_x emissions from three (3) of the 12 diesel fired electric generating units per quarter to demonstrate compliance with the cumulative NO_x emission limit in Section III.A.1 above. Each of the electric generating units must be monitored for NO_x emissions at least once during a calendar year. To meet this requirement, the permittee shall measure the NO_x emissions using a portable analyzer and a monitoring protocol approved by EPA. The permittee shall use the monitoring protocol approved by EPA in a May 6, 2002 letter (see Appendix C). Monitoring for NO_x emissions from the diesel fired electric generating units shall commence during the first complete calendar quarter following the permittee's submittal of the initial performance test results for NO_x to EPA.

2. The permittee shall monitor, every hour, the ammonia pump on each electric generating unit in operation to ensure that the pump is operating and ammonia is being injected.

III.E. <u>Recordkeeping Requirements</u>

1. The permittee shall keep a record of the number of hours of operation per calendar month and of the number of start-ups (including shut-down mode operations) per calendar month for each of the 12 diesel fired electric generating units [Units P-1, P-2, P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, and P-12]. At the end of the first calendar month, in which the units commence operation, the cumulative hours of operation and the cumulative number of start-ups shall be calculated and recorded.

   Prior to twelve full calendar months of operation under this part 71 operating permit, the permittee shall, at the end of each calendar month, add the cumulative hours of operation for that calendar month to the calculated cumulative hours of operation for all previous calendar months since permit issuance and record the total. Thereafter, the permittee shall, at the end of each calendar month, add the cumulative hours of operation for that calendar month to the calculated cumulative emissions for the preceding eleven calendar months and record a new twelve-month total. The same procedure shall be followed for calculating the cumulative number of start-ups.

2. At the end of the calendar month following the NO_x initial performance tests, individual and cumulative NO_x emissions for the 12 diesel fired electric generating units [Units P-1, P-2, P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, and P-12] shall be calculated, in tons, from the results of the initial NO_x performance tests required in condition III.C.1. These emissions calculations shall be recorded.

   Subsequent to the initial calculation, individual and cumulative NO_x emissions shall be calculated and recorded, in tons, at the end of each calendar month for the 12 diesel fired electric generating units [Units P-1, P-2, P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, and P-12], beginning with the first full calendar month after the initial calculation. Prior to twelve full calendar months of operation under this Part 71 operating permit, the permittee shall, at the end of each calendar month, add the cumulative emissions for that calendar month to the calculated cumulative emissions for all previous calendar months since permit issuance and record the total. Thereafter, the permittee shall, at the end of each calendar month, add the cumulative emissions for that calendar month to the calculated cumulative emissions for the preceding eleven calendar months and record a new twelve-month total.

3. The NO_x emissions for the 12 diesel fired electric generating units [Units P-1, P-2, P-3, P-4, P-5, P-6, P-7, P-8, P-9, P-10, P-11, and P-12] shall be calculated as follows:

   (a) Individual unit emissions, in tons, shall be calculated for the calendar month by multiplying the most recent NO_x quarterly monitoring test result for that generating unit by the number of operating hours for that generating unit for that calendar month;

   (b) Cumulative NO_x emissions, in tons, for the calendar month shall be calculated by summing the individual NO_x emissions for the 12 electric generating units.

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

   (a) Records shall be kept of all temperature measurements requirements of this permit, as well as a description of any corrective actions taken pursuant to Section III.B.7 of this permit.

   (b) Records shall be kept of all pressure drop measurements required by this permit, as well as a description of any corrective actions taken pursuant to the requirements of this permit.

   (c) Records shall be kept of vendor specifications to demonstrate that the accuracy of the temperature-sensing devices on each SCR system is at least as accurate as that required in this permit.

   (d) Records shall be kept that are sufficient to demonstrate that the maximum sulfur content of the diesel fuel fired in the electric generating units has not exceeded 0.5 percent.

III.F. Reporting Requirements

1. The permittee shall submit to EPA a written report of the results of the NO_x performance tests and temperature and pressure drop measurements required in this permit. This report shall be submitted within 60 (sixty) calendar days of the date of testing completion.

2. The permittee shall submit to EPA, as part of the semi-annual monitoring reports required by Section IV.B.1, a report of any instances where an SCR system inlet temperature deviates from the acceptable range and where the pressure drop across an SCR system deviates from the acceptable reading, as well as a description of any corrective actions. If no such instances have been detected, then a statement shall be provided to say so.

IV. 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 Section I.B.

[40 CFR 71.6(a)(1)]

IV.A. <u>General Recordkeeping Requirements</u> [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 federally recognized controls) one or more hazardous air pollutants (HAPs) 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 at the Operations Center 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. The permittee is an owner or operator of glycol dehydration units that are exempt from the control requirements under §63.764(e)(1). The permittee shall retain the GRI-GLYCalc determination used to demonstrate that actual average benzene emissions are below 1 tpy for each unit.

   [40 CFR 63.774(d)(1)]

3. Records shall be kept, as required by Section V.Q, of off permit changes made in accordance with the approved Alternative Operating Scenarios.

IV.B <u>General Reporting Requirements</u> [40 CFR 71.6(a)(3)(iii)]

1. The permittee shall submit to EPA reports of any monitoring results and recordkeeping required under this permit semi-annually by April 1st and October 1st of each year. The report due on April 1 shall cover the prior six-month period from July 1st through the end of December. The report due on October 1st shall cover the prior six-month period from January 1st through the end of June. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with Section V.E.1 of this permit.

[Explanatory note: To help Part 71 permittees meet reporting responsibilities, EPA has developed a form "SIXMON" for six-month monitoring reports. The form may be found on the EPA 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;

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

(d) A situation in which an exceedance or an excursion, as defined in 40 CFR part 64 occurs.

3. The permittee shall promptly report to 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 timeframe 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 HAPs 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 HAP or a toxic air pollutant that continue 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 required in III.B.1.

4. If any of the conditions in IV.B.3(b)(i) - (ii) are met, the source must notify EPA by telephone (1-800-227-8917) or facsimile (303-312-6064) based on the timetables listed above. *[Notification by telephone or fax must specify that this notification is a deviation report for a part 71 permit.]* A written notice, certified consistent with Section V.E.1 of this permit must be submitted within ten (10) working days of the occurrence. All deviations reported under this section must also be identified in the 6-month report required under permit Section IV.B.1.

[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 the EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

IV.C. Chemical Accident Prevention [Clean Air Act sections 112(r)(1), 112(r)(3), 112(r)(7), 40 CFR 68.10(a) and 68.215(a)(ii)]

1. A permittee of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, shall comply with the requirements of the Chemical Accident Prevention provisions at 40 CFR part 68 no later than the latest of the following dates:

   (a) June 21, 1999; or

   (b) Three (3) years after the date on which a regulated substance is first listed under 40 CFR 68.130; or

   (c) The date on which a regulated substance is first present above a threshold quantity in a process.

2. This facility is subject to part 68 and the permittee shall certify compliance with all requirements of 40 CFR part 68, including the registration and submission of the risk management plan (RMP), as part of the annual compliance certification required by 40 CFR part 71.

IV.D. Alternative Operating Scenarios - Turbine Replacement/Overhaul
[40 CFR 71.6(a)(9)]

1. Replacement of a permitted turbine with a turbine of the same make, model, heat input capacity rating, and configured to operate in the same manner as the turbine being replaced, shall be an allowed alternative operating scenario provided the replacement activity satisfies all of the provisions for Off Permit Changes under this permit (Section V.Q), including the provisions specific to turbine replacement.

2. Any emission standards, requirements, or provisions in this permit that apply to the permitted turbines shall also apply to the replacement turbines, including the initial compliance test required by 40 CFR 60.8 and subject to all other requirements of 40 CFR part 60, subpart GG.

3. Replacement of a permitted turbine with a turbine subject to 40 CFR part 60, subpart KKKK is not allowed under this alternative operating scenario.

4. Replacement of a permitted turbine with a turbine subject to 40 CFR part 63, subpart YYYY is not allowed under this alternative operating scenario.

IV.E. <u>Alternative Operating Scenario</u> – Diesel Fired Electric Generating Unit Replacement/Overhaul [40 CFR 71.6(a)(9)]

1. Replacement of a permitted generator with a generator of the same make, model, and heat input capacity rating, and configured to operate in the same manner as the generator being replaced, shall be an allowed alternative operating scenario provided the replacement activity satisfies all of the provisions for Off Permit Changes (Section V.Q.) under this permit, including the provisions specific to engine replacement.

2. Any emission standards, requirements, or provisions in this permit that apply to the permitted generators shall also apply to the replacement generators, including the initial performance test required by Section III.C of this permit and subject to all other requirements of this permit.

3. Replacement of a permitted generator with a generator subject to 40 CFR Part 60, Subpart IIII is not allowed under this alternative operating scenario.

4. Replacement of a permitted generator with a generator subject to 40 CFR Part 63, Subpart ZZZZ is not allowed under this alternative operating scenario.

[Explanatory note- Sections IV.D and IV.E were included to allow for Off Permit replacement of turbines and/or engines that may have existing federally enforceable limits. For replacement turbines and engines which trigger new applicable requirements (i.e., NSPS or MACT), the minor permit modification process (Section V.I of this permit) shall be utilized to maintain the permitted emission limits of the replaced engine and/or incorporate the new applicable requirements.]

IV.F. <u>Permit Shield</u> [40 CFR 71.6(f)(3)]

Nothing in this permit shall alter or affect the following:

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

2. The ability of EPA to obtain information from a source pursuant to section 114 of the Clean Air Act (CAA) or;

3. The provisions of section 303 of the CAA (emergency orders), including the authority of EPA under that section.

V. Part 71 Administrative Requirements

V.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 regular U.S. Postal Service mail	**For non-U.S. Postal Service Express mail** (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 US 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 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 (tpy);

[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 5 years following submittal of fee payment. [Emission-related data include, for example, emissions-related forms provided by 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 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 a fee, shall provide a written explanation of the alleged error to EPA along with full payment of the EPA assessed fee.

[40 CFR 71.9(j)(3)]

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

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 EPA by April 1st.

The annual emissions report shall be submitted to 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.]

V.C. Compliance Requirements [40 CFR 71.6(a)(6)(i) and (ii), and sections 113(a) and 113(e)(1) of the Act, and 40 CFR 51.212, 52.12, 52.33, 60.11(g), and 61.12]

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 CAA and is grounds for enforcement action; for permit termination, revocation and re-issuance, 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 this permit, 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 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 preceding calendar year.

[Explanatory note: To help Part 71 permittees meet reporting responsibilities, EPA has developed a reporting form for annual compliance certifications. The form may be found on 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 CAA, 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 the preceding paragraph of this permit. 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)]

V.D. <u>Duty to Provide and Supplement Information</u>
[40 CFR 71.6(a)(6)(v), 71.5(a)(3), and 71.5(b)]

1. The permittee shall furnish to EPA, within a reasonable time, any information that 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)]

V.E. <u>Submissions</u> [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: EPA has developed a reporting form CTAC for certifying truth, accuracy and completeness of part 71 submissions. The form may be found on EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

2. Any documents required to be submitted under this permit, including reports, test data, monitoring data, notifications, compliance certifications, 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

V.F. <u>Severability Clause</u> [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.

V.G. <u>Permit Actions</u> [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.

V.H. <u>Administrative Permit Amendments</u> [40 CFR 71.7(d)]

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

1. Corrects typographical errors;

2. 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;

3. Requires more frequent monitoring or reporting by the permittee;

4. 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;

5. 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

6. Incorporates any other type of change which EPA has determined to be similar to those listed above in subparagraphs 1 through 5 above.

[Note to permittee: If subparagraphs 1 through 5 above do not apply, please contact EPA for a determination of similarity prior to submitting your request for an administrative permit amendment under this provision.]

V.I. <u>Minor Permit Modifications</u> [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 requirements;

    (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 CAA;

    (e) Are not modifications under any provision of title I of the CAA; 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 Section V.I.1, 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 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)]

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

1. Group processing of modifications by 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 percent of the emissions allowed by the permit for the emissions unit for which the change is requested, 20 percent of the applicable definition of major source in §71.2, or 5 tpy, whichever is least.

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

2. An application requesting the use of group processing procedures shall be submitted to 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 this section of this permit;

(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)]

V.K. <u>Significant Permit Modifications</u> [40 CFR 71.7(e)(3)]

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

    (a) 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)]

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

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

1. Additional applicable requirements under the Act become applicable to a major part 71 source with a remaining permit term of 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);

2. 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;

3. 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

4. EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

V.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.

V.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 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 CAA, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

V.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 EPA within 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 proceedings 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.

V.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 EPA.

V.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 at the Operations Center for a period of five years:

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

2. Each change shall meet 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 CAA;

4. The permittee must provide contemporaneous written notice to 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;

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; and

7. Replacement of a 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, shall satisfy the following provisions:

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

   (b) The replacement of the existing turbine must 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 must be provided in a written notice to EPA, prior to installation of the replacement turbine, in addition to the standard information listed above for contemporaneous written notices for off permit changes:

      (i) Make, model number, serial number MMBtu/hr and configuration of the permitted turbine and the replacement turbine;
      (ii) Manufacturer date, commence construction date (per the definitions in 40 CFR 60.2, 60.4230(a), and 63.2), and installation date of the replacement turbine at the facility;
      (iii) If applicable, documentation of the cost to rebuild a replacement turbine versus the cost to purchase a new turbine in order to support claims that a turbine is not "reconstructed," as defined in 40 CFR 60.15 and 63.2;
      (iv) 40 CFR part 60, subpart KKKK (New Turbine NSPS) non-applicability documentation;
      (v) 40 CFR part 63, subpart YYYY (Turbine MACT) non-applicability documentation; and
      (vi) 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) <u>If the existing source is a "major stationary source" as defined in §52.21(b)(1)</u>: 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 <u>net</u> 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) <u>If the existing source is not a "major stationary source" as defined in §52.21(b)(1)</u>: For each "regulated NSR pollutant," a demonstration (including all calculations) that the replacement turbine(s), by itself, will not constitute a "major stationary source" as defined in §52.21(b)(1)(i).

8. For replacement of a permitted engine with an engine of the same make, model, horsepower rating, and configured to operate in the same manner as the engine being replaced, in addition to satisfying all other provisions for Off Permit Changes, the permittee satisfies the following provisions:

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

(b) The replacement of the permitted engine 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 EPA, prior to installation of the replacement engine, 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 permitted engine and the replacement engine;
(ii) Manufacturer date, commence construction date (per the definitions in 40 CFR 60.2, 60.4230(a), and 63.2), and installation date of the replacement engine at the facility;
(iii) If applicable, documentation of the cost to rebuild a replacement engine versus the cost to purchase a new engine in order to support claims that an engine is not "reconstructed," as defined in 40 CFR 60.15 and 63.2;
(iv) 40 CFR part 60, subpart IIII (CI Engine NSPS) non-applicability documentation;
(v) 40 CFR part 60, subpart JJJJ (SI Engine NSPS) non-applicability documentation;
(vi) 40 CFR part 63, subpart ZZZZ (RICE MACT) non-applicability documentation for major HAP sources;
(vii) 40 CFR part 63, subpart ZZZZ (RICE MACT) non-applicability documentation for area sources; and
(viii) 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) <u>If the existing source is a "major stationary source" as defined in §52.21(b)(1)</u>: 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).

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

10. 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 turbine, by replacement of multiple turbines, by the replacement of any one engine, or by the replacement of multiple engines.

V.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 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)]

VI. Appendix

VI.A. Inspection Information

1. Directions to Plant:

   From the City of Durango, Colorado go east on Highway 172 to County Road 307. Then go south on County Road 307 for approximately 2.8 miles. Then go east into the Florida River Compression Facility.

2. Latitude and Longitude Coordinates

   Lat. 37-09-23.0 Long. -107-46-50.0

3. Safety Considerations

   All visitors to the BP American Production Company's Florida River Compression Facility are required to wear a hard hat, safety glasses, safety shoes, hearing protection and fire retardant clothing.

VI.B. Custom Fuel Monitoring Schedule and Approval – Attached

VI.C. Portable Analyzer Monitoring Protocol and Approval – Attached