UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-AR

MAR 28 2008

Kourtney K. Hadrick, Florida Operations Manager
BP America Production Company
380 Airport Road
Durango, CO 81303

Re: Draft Renewal Title V Permit
#V-SU-0022-05.00
BP America Production Company
Florida River Compression Facility

Dear Ms. Hadrick:

The Environmental Protection Agency, Region 8 (EPA), has completed its review of BP America Production Company's application for the Florida River Compression Facility to obtain a renewed title V operating permit pursuant to 40 CFR part 71. The application was received December 1, 2005.

On November 8, 2007, EPA sent a letter to inform you of a new mailing address, effective December 17, 2007, for the submittal of annual fee payments required pursuant to 40 CFR part 71 and the title V permits issued by EPA's Office of Air. The fee payment bank name and address have been corrected in the permit. Additionally, in an effort to streamline the title V permits and reduce the number of administrative permit amendments requested, EPA is removing specific non-enforceable facility information, such as the names and phone numbers of the Responsible Official, Facility Contact, and Tribal Contact, as well as the plant mailing address. Part 71 does not require this information to be in the permit and changes to such information are the most often requested administrative permit amendments. This information will be maintained in the Statements of Basis for each permit action. EPA requests from this point forward that BP America Production Company continue to send notification in writing of changes to such facility information; however, the changes will no longer require administrative permit amendments.

Enclosed you will find the draft title V operating permit and the corresponding Statement of Basis. 40 CFR 71.11(d) requires that an applicant, the public, and affected states have the opportunity to submit written comments on any draft part 71 operating permit. All written comments submitted within 30 (thirty) calendar days after the public notice is published will be considered by EPA Region 8 in making its final permit decision. Public notice will be published in the Durango Herald on April 18, 2008. The public comment period will end on May 19, 2008.

The conditions contained in the permit will become effective and enforceable by EPA if the permit is issued final. If you are unable to accept any term or condition of the draft permit, please submit your written comments, along with the reason(s) for non-acceptance to:

Part 71 Permitting Contact
U.S. EPA, Region VIII
Air Program (8P-AR)
1595 Wynkoop Street
Denver, Colorado 80202

If you have any questions concerning the enclosed draft permit or the Statement of Basis, you may contact Kathleen Paser, of my staff, at (303) 312-6526.

Sincerely,

Callie A. Videtich, Director
Air Program

Enclosures

cc: Julie A. Best, BP America Production Company, Environmental Coordinator
Rebecca Tanory, BP America Production Company, Environmental Specialist
Christopher Lee, SUIT, Air Program Manager

Air Pollution Control
Title V Permit to Operate
Statement of Basis for Draft Permit No. V-SU-0022-05.00
Renewal #1

BP America Production Company
Florida River Compression Facility
Southern Ute Indian Reservation
La Plata County, Colorado

1. Facility Information

a. Location

The Florida River Compression Facility, owned and operated by BP America Production Company, is located within the exterior boundaries of the Southern Ute Indian Reservation, in the southwestern part of the State of Colorado, in La Plata County. The coordinates are SE/4, SW/4 of Section 25, Township 34N, Range 9W. The parent company mailing address is:

BP America Production Company
501 Westlake Park Blvd.
Houston, Texas 77079

b. Contacts

Facility Contact:

Julie A. Best
Environmental Coordinator
380 Airport Road
Durango, CO 81303
970-247-6913
970-375-7586 (fax)

Responsible Official:

Kourtney K. Hadrick
Florida Operations Manager
2906 County Road 307
Durango, CO 81303
970-247-6901
970-247-6910 (fax)

Company Contact:

Rebecca Tanory
Environmental Specialist
501 Westlake Boulevard
Houston, TX 77079
281-366-3945

Alternate Responsible Official:

David P. McKenna
Durango Operations Manager
380 Airport Road
Durango, CO 81303
970-247-6810
970-247-6825 (fax)

Tribal Contact:

Christopher Lee
SUIT Air Program Director
970-563-4705

c. Description of operations

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 dehy header such that all gas is blended and identical going to the three dehys. 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 CO2 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 2922 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.

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.

d. Permitting and/or construction history

BP America Production Company's Florida River Compression Facility was initially permitted by the Colorado Department of Public Health and Environment (CDPHE) in 1987, under the name of Amoco Production Company. This facility was a minor source for both the Prevention of Significant Deterioration (PSD) and the title V operating permit programs. Amoco Production Company then obtained ownership and operation of two nearby turbines from El Paso Natural Gas Company. The first natural gas-fired simple cycle turbine was installed in 1995, unit A-01. The second simple cycle turbine was installed in 1999, unit A-02. The El Paso turbines were considered a major source under the title V program and a minor source under the PSD program.

The El Paso Natural Gas Company's Florida River Compressor Station (2- turbines) and the BP America Production Company's (previously Amoco) Florida River Compression Facility were each individually minor sources under the PSD permitting program. Upon BP America Production Company obtaining the ownership/operator status of the El Paso turbines, the combined Florida River Compression Facility is now considered as one source and as a major source under the PSD and title V rules. Future major modifications to the Florida River Compression Facility will trigger the PSD permitting requirements.

Past modifications to each of the facilities (Amoco and El Paso Natural Gas) were permitted by CDPHE. The Florida River Compression Facility is located within the exterior boundaries of the Southern Ute Indian Reservation, and therefore the State of Colorado's minor source pre-construction permit program does not apply to this facility. EPA has no record of any federal air permitting activity at either the two separate facilities or the now combined Florida River Compression Facility. Consequently, there are no federal pre-construction permits.

The Federal Title V Operating Permit Program became effective in February of 1999. Since the El Paso Natural Gas Company's Florida River Compressor Station is within the exterior boundaries of the S. Ute Indian Reservation, EPA Region 8 asserted jurisdiction over the regulation of this facility for purposes of the Clean Air Act (CAA) and in March of 2000, a part 71 application was received by the Regional office.

An initial part 71 permit was issued for the facility on June 5, 2001.

In July/August 2001, BP America Production Company installed a gas-fired Waukesha L579T lean burn compressor engine. The emissions increase from the installation of this engine did not trigger PSD requirements. Subsequently, this engine has been removed.

On June 4, 2004, EPA issued a significant modification to the BP America Production Company's part 71 permit to establish synthetic minor limits for NOx emissions for 12-yet-to-be-installed diesel generators. The permit established enforceable requirements to control nitrogen oxide (NOx) emissions with an add-on selective catalytic reduction (SCR) system from each generator. In addition, EPA established an enforceable NOx emissions limit cap over all of the generators of 39.1 tons per years and limited the total annual hours of operation for all 12 generators to 12,900 hours. These proposed limits made the modification a minor PSD modification to a major PSD stationary source, and thus the modification of the facility was not subject to the PSD permitting requirements.

On December 1, 2005, EPA received an application for renewal of the part 71 permit. In a letter dated January 21, 2006, EPA determined the application to be complete on January 19, 2006.

e. List of all units and emission-generating activities

BP America Production Company provided in its Florida River Compression Facility application and applications for modifications the information contained in Tables 1 and 2. Table 1 lists emission units and emission generating activities, including any air pollution control devices. Emission units identified as "insignificant" are listed separately in Table 2.

Part 71 allows sources to separately list in the permit application units or activities that qualify as "insignificant" based on potential emissions below 2 tons/year for all regulated pollutants that are not listed as a hazardous air pollutant (HAP) under Clean Air Act (CAA) section 112(b) and below 1000 lbs/year or the de minimis level established under section 112(g), whichever is lower, for HAPs. However, the application may not omit information needed to determine the applicability of, or to impose, any applicable requirement, or to calculate the fee. Units that qualify as insignificant for the purposes of the part 71 application are in no way exempt from applicable requirements or any requirements of the part 71 permit.

Table 1 - Emission Units
BP America Production Company
Florida River Compression Facility

Emission Unit Id. No.	Description	Control Equipment
	45 MMBtu/hr Solar Centaur H T5500 Turbine. Natural gas fired, simple cycle:	
T-1	Serial Number: 0690-H Installed: 1995	
T-2	Serial Number: 0307-H Installed: 08/1999	None
	44.5 mmBtu/hr Amine Heater #1. Natural gas fired:	
AH-1	Serial Number: 421 Installed: 1990 (Const. 5/30/1989)	None
	44.0 mmBtu/hr Amine Heater #2. Natural gas fired:	
AH-2	Serial Number: 2440 Installed: 1997 (Const. 1980)	None
	70 MMscfd Amine Unit #1 Still Vent:	
AV-1	Serial Number: NA Installed: 1990	None
	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	
Plant Flare	VECO Custom Ground Flare Installed: 1/2004	None
	2922 hp Cummins QSK60; Diesel-fired electric generation unit:	
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	Selective
P-9	Serial Number: 1000155269 Installed: 4/2004	Catalytic
P-10	Serial Number: 1000148783 Installed: 4/2004	Reduction
P-11	Serial Number: L000190130 Installed: 4/2004	(90% NOx
P-12	Serial Number: K000172346 Installed: 4/2004	Reduction)

Table 2 - Insignificant Emission Units
BP America Production Company
Florida River Compression Facility

Description
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 #9 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
1 - 300 gal Diesel Tank
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 Oil Drain and Sump
6 - 55 gal Lube Oil Tanks

f. Potential to emit

Potential to emit means the maximum capacity of the BP America Production Company's Florida River Compression Facility to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the BP America Production Company's Florida River Compression Facility to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, may be treated as part of its design if the limitation is enforceable by EPA. Potential to emit is meant to be a worse case emissions calculation. Actual emissions may be much lower.

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] are equipped with SCR systems to control emissions of NOx. BP America Production Company requested the use of the SCR systems to limit emissions of NOx from 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.

National EPA guidance states that air pollution control equipment (in this case, the SCR systems) can be credited as restricting PTE only if federally enforceable requirements are in place requiring the use of such air pollution control equipment. (Reference: letter dated November 27, 1995, from David Solomon, Acting Group Leader, Integrated Implementation Group, Office of Air Quality Planning & Standards, U.S. EPA, to Timothy Mohin of Intel Government Affairs.) A cumulative emissions limit for NOx in tons per year is established in the permit as an enforceable condition for 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, as well as, a limit on the cumulative number of hours of operation for the 12 diesel fired electric generating units.

In consultation with Office of General Counsel at EPA Headquarters, as well as with EPA Regions 9 and 10, the EPA Region 8 office determined that authority exists under the CAA and 40 CFR 71 to create a restriction on potential to emit through issuance of a part 71 permit. The specific citations of authority are:

CAA Section 304(f)(4): provides that the term "emission limitation, standard of performance or emission standard" includes any other standard, limitation, or schedule established under any permit issued pursuant to title V ... , any permit term or condition, and any requirement to obtain a permit as a condition of operations.

40 CFR 71.6(b): provides that all terms and conditions in a part 71 permit, including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator and citizens under the Act.

40 CFR 71.7(e)(1)(i)(A)(4)(*i*): provides that a permit modification that seeks to establish a federally enforceable emissions cap assumed to avoid classification as a modification under any provision of title I of the CAA (which includes PSD), and for which there is no underlying applicable requirement, does not qualify as a minor permit modification. Under 40 CFR 71.7(e)(3)(i), it is therefore a significant permit modification, which, according to 40 CFR 71.7(e)(3)(ii), must meet all the requirements that would apply to initial permit issuance or permit renewal.

An enforceable limit on the NOx emissions for 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 will reduce potential NOx emissions to 39.1 tons per year. Adequate testing, monitoring, reporting, and recordkeeping requirements have also been included as permit conditions to make the restrictions on potential emissions and hours of operation a practical matter.

The potential to emit for the facility as a whole are as follows:

Nitrogen Oxides (NOx) – 282.07 tpy
Carbon Monoxide (CO) – 181.94 tpy
Volatile Organic Compounds (VOC) – 30.27 tpy
Small Particulates (PM_{10}) – 7.95 tpy
Sulfur Dioxide (SO_2) – 24.23 tpy
Total Hazardous Air Pollutants (HAPs) – 4.14 tpy
Largest Single HAP (formaldehyde, CH_2O) – 1.20 tpy

2. Tribe Information

a. Indian country:

The BP Florida River Compression Facility is located within the exterior boundaries of the Southern Ute Indian Reservation and is thus within Indian country as defined at 18 U.S.C. §1151. The Southern Ute Tribe does not have a federally-approved Clean Air Act (CAA) title V operating permits program nor does EPA's approval of the State of Colorado's title V program extend to Indian country. Thus, EPA is the appropriate governmental entity to issue the title V permit to this facility.

b. The Reservation:

The Southern Ute Indian Reservation is located in Southwestern Colorado adjacent to the New Mexico boundary. Ignacio is the headquarters of the Southern Ute Tribe, and Durango is the closest major city, just 5 miles outside of the north boundary of the Reservation. Current information indicates that the population of the Tribe is about 1,305 people with approximately 410 tribal members living off the Reservation. In addition to Tribal members, there are over 30,000 non-Indians living within the exterior boundaries of the Southern Ute Reservation.

c. Tribal government:

The Southern Ute Indian Tribe is governed by the Constitution of the Southern Ute Indian Tribe of the Southern Ute Indian Reservation, Colorado adopted on November 4, 1936 and subsequently amended and approved on October 1, 1975. The Southern Ute Indian Tribe is a federally recognized Tribe pursuant to section 16 of the Indian Reorganization Act of June 18, 1934 (48 Stat.984), as amended by the Act of June 15, 1935 (49 Stat. 378). The governing body of the Southern Ute Indian Tribe is a seven member Tribal Council, with its members elected from the general membership of the Tribe through a yearly election process. Terms of the Tribal Council are three years and are staggered so in any given year 2 members are up for reelection. The Tribal Council officers consist of a Chairman, Vice-Chairman and Treasurer.

d. Local air quality and attainment status:

The Tribe maintains an air monitoring network consisting of two sites equipped to collect Oxides of Nitrogen (NO_2), Ozone (O_3), Carbon Monoxide (CO) and meteorological data. The Tribe has collected NO_2 and O_3 data at the Ignacio site and Bondad site since June 1, 1982, and April 1, 1997, respectively. Since January 1, 2000, both sites initiated meteorological monitors measuring Wind Speed, Wind Direction, Vertical Wind Speed, Outdoor Temperature, Relative Humidity, Solar Radiation, and Rain/Snow Melt Precipitation. Particulate data (PM_{10}) was collected from December 1, 1981 to September 30, 2006, at the Ignacio site and since April 1, 1997 to September 30, 2006, at the Bondad site. The monitors indicate the following averages for the pollutant monitored: An annual average for NO_2, an hourly average for O_3 and CO, an 8-hour average for CO.

3. Applicable Requirements

a. Applicable Requirement Review:

Based on the information provided by BP America Production Company in its applications, the Florida River Compression Facility is subject to the following applicable requirements:

Emission Limits, Testing, and Monitoring: BP America Production Company requested a cumulative NOx emission limit of 39.1 tons per year and a limit on the hours of operation 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] in order to avoid applicability to the PSD permitting requirements (40 CFR 52.21). In order to determine initial compliance with the established NOx permit limit, a requirement for reference method performance testing for NOx is also included as a permit condition.

Determining continuing compliance with the cumulative NOx limit will be accomplished using a portable analyzer to monitor for NOx emissions. The inlet temperatures to the SCR systems and pressure drops across the SCR systems will be measured when each unit is operating. Each generating unit has an ammonia injection pump for the SCR system. These ammonia pumps will also be monitored to ensure the pump is running and ammonia is being injected.

In order for the SCR system to effectively reduce NOx emissions, the inlet temperature to the SCR system must be maintained at all times a generating unit operates at no less than 500°F and no more than 1200°F. The pressure drop across each SCR system must be maintained to within four (4) inches of water from the baseline pressure drop reading taken during the initial performance test for each generating unit.

New Source Performance Standard (NSPS)

40 CFR Part 60, Subpart A: General Provisions. This subpart applies to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication of any standard in part 60. The general provisions under subpart A apply to sources that are subject to the specific subparts of part 60. The Florida River Compression Facility is subject to the provisions of 40 CFR part 60, subpart GG. Therefore, the general provisions of 40 CFR part 60 also apply.

40 CFR Part 60, Subpart GG: Standards of Performance for Stationary Gas Turbines. This rule applies to *stationary gas turbines, with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10* MMBtu/hr), that commenced construction, modification, or reconstruction after October 3, 1977.

Turbine units T-1 and T-2 were constructed after October 3, 1977. Each turbine also has a heat input at peak loads greater than10 MMBtu/hr and each is subject to NSPS-subpart GG. Units T-1 and T-2 are subject to the NOx standard at 40 CFR 60.332(a)(2) and the sulfur in fuel standard at 40 CFR 60.333(b).

Periodic Monitoring: The monitoring requirements contained in 40 CFR part 60, subpart GG only require that a one time performance test for NOx be conducted to demonstrate initial compliance with the requirements of 40 CFR 60.332. No additional testing or monitoring of NOx emissions is required under this NSPS.

The *Appalachian Power* court held that 40 CFR 71.6(a)(3)(i) authorizes a sufficiency review of monitoring and testing in an existing emissions standard, and enhancement of that monitoring or testing through the permit, when the standard requires no periodic testing or instrumental or noninstrumental monitoring, specifies no frequency, or requires only a one-time test. Thus, EPA has authority in the federal operating permit regulation to specify additional testing or monitoring for a source to assure compliance, when existing applicable regulations do not require periodic monitoring or only require a one-time emissions test.

Because 40 CFR part 60, subpart GG requires that a one-time compliance test for NOx emissions be conducted for a subject turbine, additional monitoring of the turbines for assuring compliance with the NOx emission limit has been included in the permit. Appropriate periodic monitoring for the gas-fired turbines was determined to be quarterly monitoring of NOx emissions using a portable analyzer.

Off Permit Changes and Alternative Operating Scenarios: BP America Production Company's Florida River Compression Facility permit allows for turbine replacements. Language has been included in the permit to allow for off permit replacement of individual simple cycle turbines with new or overhauled turbines, provided that each replacement turbine is the same make, model, heat input capacity rating, configuration, and with equivalent air emission controls, as the turbine it replaces, and provided that the provisions in the Off Permit Changes section of the permit, specific to turbine replacement, are satisfied. The primary purpose of the Off Permit Changes provisions is to ensure that NESHAP and NSPS requirements are not triggered and that PSD permitting requirements are not circumvented by off permit changes. Related language is also included in the section on Alternative Operating Scenarios.

Similar emission unit replacement language has been included in the permit for the 12 diesel fired electric generating units.

Streamlined Permit Condition: The custom fuel monitoring schedule approved by EPA per 40 CFR part 60, subpart GG requires that BP America Production Company retain records of any sample analysis, fuel supplier, fuel supply, fuel quality, and fuel make-up for a period of two years. Section II.A. of White Paper 2 allows conflicting requirements on the same emissions unit to be streamlined into one enforceable permit condition, as long as the most stringent of the multiple applicable requirements is determined. Section 71.6(a)(3)(ii) requires that the permittee retain records, data, etc. for a period of at least five years. The two year record retention requirement was streamlined with the five year requirement and is found in section II.E.8. of the permit.

Chemical Accident Prevention

Based on BP America Production Company's application, its Florida River Compression Facility has a regulated substance listed in 112(r) of the CAA that is above the threshold quantity. BP America Production Company is therefore subject to the requirement to develop and submit a risk management plan (RMP). The Florida River Compression Facility has on site in excess of 10,000 pounds of ammonia, which is used in the refrigeration cooling system. The risk management plan for the Florida River Compression Facility was received by EPA on June 23, 1999 and was determined complete on July 14, 1999. The Plan Sequence Number is 12123. This number uniquely identifies the RMP for each subject facility.

b. The following Federal applicable requirements have been considered for applicability to BP America Production Company's Florida River Compression Facility.

Based on information supplied by BP America Production Company in its applications, it was determined that the Florida River Compression Facility is **not** subject to these requirements.

Stratospheric Ozone and Climate Protection - Subpart F
The Florida River Compression Facility has several air conditioning units that utilize freon as the refrigerant. There are 6 air conditioning units in the office space, 11 air conditioning units in the electrical compression buildings, and 4 other units located throughout the facility. BP America Production Company does not service, maintain, repair or dispose of appliances pursuant to 40 CFR part 82, subpart F. Only certified contractors are used to provide these services. If BP America Production Company ever services, repairs, maintains, or disposes of any of the air conditioning units, then BP America Production Company must comply with the standards of 40 CFR subpart F, specifically, §82.156, §82.158, §82.161, and §82.166(i), and request a significant modification to this part 71 permit.

Stratospheric Ozone and Climate Protection - Subpart H
The Florida River Compression Facility does not have fire extinguishers on site that use halon, so 40 CFR part 82, subpart H for halon emissions reduction does not apply. If BP America Production Company ever decides to use fire extinguishers that use halon and use its personnel to service, maintain, test, repair, or dispose of equipment that contains halons or use such equipment during technician training, then it must comply with the standards of 40 CFR part 82, subpart H for halon emissions reduction and request a significant modification to this part 71 permit.

Prevention of Significant Deterioration (PSD)
A review of BP America Production Company's applications for the Florida River Compression Facility shows that the potential to emit of any pollutant regulated under the Clean Air Act [not including pollutants listed under section 112] is less than the 250 tons per year PSD major source threshold, except for NOx emissions. The potential NOx emissions are about 282 tons per year.

The El Paso Natural Gas Company's Florida River Compressor Station (2- turbines) and the BP America Production Company's (previously Amoco) Florida River Compression Facility were each individually minor sources under the PSD permitting program. Upon BP America Production Company obtaining the ownership/operator status of the El Paso turbines, the combined Florida River Compression Facility is now considered as one source and as a major source under the PSD rules. While this combined facility has never been required to receive a PSD permit to construct, significant emission increases due to modifications at the facility could trigger the PSD permitting requirements.

BP America Production Company requested an enforceable limit of 39.1 tons per year on the cumulative NOx emissions from 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 its application for a significant permit modification on February 10, 2004. The federally enforceable limit, established in the permit (prior to construction of the modification) made the modification a minor modification to a major stationary source, and thus it was not subject to the PSD permitting requirements.

New Source Performance Standards (NSPS)

40 CFR Part 60, Subpart K: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. Subpart K does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

The Florida River Compression Facility has many tanks on site that are of various sizes and which contain various substances (i.e. gasoline, diesel, lube oil, etc.). The largest tank is 400 bbls.(12,600 gallons). Information from the applications indicates that initial construction of this facility occurred in the timeframe of 1987-1989. Due to the sizes of the tanks and the date of construction of the site, this rule does not apply.

40 CFR Part 60, Subpart Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to June 23, 1984. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. Subpart Ka does not apply to petroleum storage vessels with a capacity of less than 420,000 gallons used for petroleum or condensate stored, processed, or treated prior to custody transfer.

The Florida River Compression Facility has many tanks on site that are of various sizes and which contain various substances (i.e. gasoline, diesel, lube oil, etc.). The largest tank is 400 bbls.(12,600 gallons). Information from the application indicates that initial construction of this facility occurred in the timeframe of 1987-1989. Due to the sizes of the tanks and the date of construction of the site, this rule does not apply.

40 CFR Part 60, Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This rule applies to storage vessels with a capacity greater than or equal to 75 cubic meters used to store volatile organic liquids (VOLs).

All tanks on site have a capacity less than 75 cubic meters. Therefore, this rule does not apply.

40 CFR Part 60, Subpart KKK: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This rule applies to compressors and other equipment at onshore natural gas processing facilities. As defined in this subpart, a natural gas processing plant is any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. Natural gas liquids are defined as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

The Florida River Compression Facility does not extract natural gas liquids from field gas and therefore does not meet the definition of a natural gas processing plant under this subpart. Therefore, this rule does not apply.

40 CFR Part 60, Subpart LLL: Standards of Performance for Onshore Natural Gas Processing; SO_2 Emissions. This rule applies to sweetening units and sulfur recovery units at onshore natural gas processing facilities. As defined in this subpart, sweetening units are process devices that separate hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from a sour natural gas stream. Sulfur recovery units are defined as process devices that recover sulfur from the acid gas (consisting of H_2S and CO_2) removed by a sweetening unit.

The Florida River Compression Facility does not perform sweetening or sulfur recovery at the site. Therefore, this rule does not apply.

40 CFR Part 60, Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. This rule applies, in part, to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005 where the stationary CI ICE are:

a. Manufactured after April 1, 2006 and are not fire pump engines, or
b. Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

This subpart also applies to owners and operators of stationary CI ICE that modify or reconstruct their stationary ICE after July 11, 2005.

BP operates 12 CI ICE at the Florida River Compression Facility. However, construction commenced on all 12 engines before July 11, 2005. In addition and according to BP, these twelve engines have not been modified or reconstructed after July 11, 2005. Therefore, this rule does not apply at this time.

40 CFR Part 60, Subpart KKKK: Standards of Performance for Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005. The rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour.

The turbines operating at the Florida River Compression Facility were initially installed prior to February 18, 2005, and EPA has no information that indicates that the turbines have been replaced with new units or have been modified or reconstructed after February 18, 2005. Therefore, based on the information provided by BP, this rule does not apply.

National Emissions Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 63, Subpart A: General Provisions. This subpart contains national emissions standards for HAPs that regulate specific categories of sources that emit one or more HAP regulated pollutants under the CAA. The general provisions under subpart A apply to sources that are subject to the specific subparts of part 63.

The Florida River Compression Facility is subject to standards of 40 CFR part 63. However, the facility is only subject to minimal record keeping of the area source standards of 40 CFR 63, subpart HH and the rule exempts area sources from the requirements of the general provisions of part 63. Therefore, the Florida River Compression Facility is not subject to the general provisions of 40 CFR part 63.

40 CFR Part 63, Subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. This subpart applies to the owners and operators of affected units located at natural gas production facilities that are major sources of HAP's, and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. The affected units are glycol dehydration units, storage vessels with the potential for flash emissions, and the group of ancillary equipment, and compressors intended to operate in volatile hazardous air pollutant service, which are located at natural gas processing plants.

Throughput Exemption:

Those sources whose maximum natural gas throughput, as appropriately calculated in §63.760(a)(1)(i) through (a)(1)(iii), is less than 18,400 standard cubic meters per day are exempt from the requirements of this subpart.

Source Aggregation:

Major source, as used in this subpart, has the same meaning as in §63.2, except that:

1.) Emissions from any oil and gas production well with its associated equipment and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units.

2.) Emissions from processes, operations, or equipment that are not part of the same facility shall not be aggregated.

3.) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage tanks with flash emission potential shall be aggregated for a major source determination.

Facility:

For the purpose of a major source determination, facility means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in subpart HH. Examples of facilities in the oil and natural gas production category include, but are not limited to: well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Production Field Facility:

Production field facilities are those located prior to the point of custody transfer. The definition of custody transfer (40 CFR 63.761) means the point of transfer after the processing/treating in the producing operation, except for the case of a natural gas processing plant, in which case the point of custody transfer is the inlet to the plant.

Natural Gas Processing Plant:

A natural gas processing plant is defined in 40 CFR 63.761 as any processing site engaged in the extraction of NGL's from field gas, or the fractionation of mixed NGL's to natural gas products, or a combination of both. A treating plant or compression facility that does not engage in these activities is considered to be production field facilities.

Major Source Determination for Production Field Facilities:

The definition of major source in this subpart (at 40 CFR §63.761) states, in part, that only emissions from the dehydration units and storage vessels with a potential for flash emissions at production field facilities are to be aggregated when comparing to the major source thresholds. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated.

Area Source Applicability

40 CFR part 63, subpart HH applies to area sources of HAPs. An area source is a HAP source whose total HAP emissions are less than 10 tpy of any single HAP or 25 tpy for all HAPs in aggregate. This subpart requires different emission reduction requirements for triethylene glycol dehydration units found at oil and gas production facilities based on their geographical location. Units located in densely populated areas (determined by the Bureau of Census) and known as urbanized areas with an added 2-mile offset and urban clusters of 10,000 people or more, are required to have emission controls. Units located outside these areas will be required to have the glycol circulation pump rate optimized or operators can document that PTE of benzene is less than 1 tpy.

Applicability of subpart HH to the Florida River Compression Facility:

The Florida River Compression Facility does not engage in the extraction of NGL's and therefore is not considered a natural gas processing plant. Hence, the point of custody transfer, as defined in this subpart HH, occurs downstream of the station and the facility would therefore be considered a production field facility. For production field facilities, only emissions from the dehydration units and storage vessels with a potential for flash emissions are to be aggregated to determine major source status. The facility does not have flash tanks and the HAP emissions from the dehydration units alone at the facility are below the major source thresholds of 10 tons per year of a single HAP and 25 tons per year of aggregated HAP's.

With respect to the area source requirements of this subpart, the facility is located outside both an urban area and an urban cluster. Furthermore, uncontrolled benzene emissions from each of the TEG units at the facility were determined to be less than 1 tpy using GRI-GLYCalc Version 4.0, as presented in the supporting documentation in the application. **As a result, each dehydration unit at the facility is**

exempt from the §67.764(d) general requirements for area sources. However, the following general recordkeeping requirement does apply to this facility:

- §63.774(d)(1) – retain the GRI-GLYCalc determinations used to demonstrate that actual average benzene emissions are below 1 tpy.

40 CFR Part 63, Subpart HHH: National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. This rule applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user, and that are major sources of hazardous air pollutant (HAP) emissions. Natural gas transmission means the pipelines used for long distance transport and storage vessel is a tank or other vessel designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon, liquids, produced water or other liquid and is constructed of wood, concrete, steel or plastic structural support. A compressor station that transports natural gas prior to the point of custody transfer or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage source category.

This subpart does not apply to the Florida River Compression Facility as the facility is a natural gas production facility and not a natural gas transmission or storage facility.

40 CFR Part 63, Subpart YYYY: National Emission Standards for Hazardous Air Pollutants from Stationary Combustion Turbines. This rule establishes national emission limitations and work practice standards for HAPs emitted from Stationary Combustion Turbines. The affected source includes the stationary combustion turbine located at a major source of HAP emissions.

Stationary Combustion Turbine:

Stationary combustion turbines are defined in §63.6175 as all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary meansthat the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Major Source:

Major source for purposes of this subpart has the same meaning as provided in 40 CFR 63.2 with the exception that emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or station are major sources, even when emission points are in a contiguous are or under common control.

Applicability to the Florida River Compression Facility:

The Florida River Compression Facility is not subject to this subpart because it is not a major source of HAPs as determined from the requirements of this rule.

40 CFR Part 63, Subpart ZZZZ: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This rule establishes national emission limitations and operating limitations for HAPs emitted from stationary reciprocating internal combustion engines (RICE). A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile.

This rule applies to owners or operators of new and reconstructed stationary RICE of any horsepower rating which are located at a major or area source of HAP. While all stationary RICE located at major or area sources are subject to the final rule (promulgated January 18, 2008, amending the final rule promulgated June 15, 2004), there are distinct requirements for regulated stationary RICE depending on their design, use, horsepower rating, fuel, and major or area HAP emission status. The standards in the final rule have specific requirements for most new or reconstructed RICE and for existing spark ignition (SI) 4 stroke rich burn (4SRB) stationary RICE. With the exception of the existing spark ignition 4SRB stationary RICE, other types of existing stationary RICE (i.e., SI 2 stroke lean burn (2SLB), SI 4 stroke lean burn (4SLB), compression ignition (CI), stationary RICE that combust landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, emergency, and limited use units) located at major and area sources of HAP emissions are not subject to any specific requirements under the final rule.

Major Source Applicability

Pursuant to 40 CFR 63.6590, a stationary RICE with a site rating of greater than 500 bhp is existing at a major source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced before December 19, 2002. A stationary RICE with a site rating of less than or equal to 500 bhp is existing at a major source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced before June 12, 2006. A stationary RICE with a site rating of greater than 500 bhp is new at a major source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced on or after December 19, 2002. A stationary RICE with a site rating of less than or equal to 500 bhp is new at a major source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced on or after June 12, 2006.

BP's Florida River Compression Facility is a minor source for HAPs. Therefore, the CI ICE engines are not subject to the major source standards of this subpart.

Area Source Applicability

Pursuant to 40 CFR 63.6590 a stationary RICE is existing at an area source of HAP emissions if construction or reconstruction of the unit commenced before June 12, 2006. A stationary RICE is new at an area source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced on or after June 12, 2006.

The 12 CI ICE engines located at the facility are existing units having been constructed before June 12, 2006. Therefore, the Florida River Compression Facility is not subject to the area source standards of this subpart.

Compliance Assurance Monitoring (CAM) Rule

According to 40 CFR 64.2(a), the CAM rule applies to each Pollutant Specific Emission Unit (PSEU) that meets the following three criteria: 1) is subject to an emission limitation or standard, and 2) uses a control device to achieve compliance, and 3) has pre-control emissions that exceed or are equivalent to the major source threshold.

The turbines at the Florida River Compression Facility are subject to an emission limit, but neither of the turbines use any add-on control devices to achieve compliance. Therefore, the turbines are not subject to the CAM requirements.

The 12 diesel fired electric generating units are not each subject to an individual emission limit. The generating units are subject to a cumulative limit on NOx emissions and each unit uses a control device (SCR) to reduce NOx emissions. The permittee requested that the control devices and cumulative limit on NOx emissions be made enforceable conditions in the part 71 permit. The pre-control NOx emissions of each unit do not exceed the major source threshold of 100 tons per year. Therefore, the generating units are not subject to the CAM requirements.

c. Conclusion

Since the Florida River Compression Facility is located in Indian country, the State of Colorado's implementation plan does not apply to this source. In addition, no tribal implementation plan (TIP) has been submitted and approved for the Southern Ute Tribe, and EPA has not promulgated a federal implementation plan (FIP) for the area of jurisdiction governing the Southern Ute Indian Reservation. Therefore, the Florida River Compression Facility is not subject to any implementation plan.

EPA recognizes that, in some cases, sources of air pollution located in Indian country are subject to fewer requirements than similar sources located on land under the jurisdiction of a state or local air pollution control agency. To address this regulatory gap, EPA is in the process of developing national regulatory programs for preconstruction review of major sources in nonattainment areas and of minor sources in both attainment and nonattainment areas. These programs will establish, where appropriate, control requirements for sources that would be incorporated into part 71 permits. To establish additional applicable, federally-enforceable emission limits, EPA Regional Offices will, as necessary and appropriate, promulgate FIPs that will establish federal requirements for sources in specific areas. EPA will establish priorities for its direct federal implementation activities by addressing as its highest priority the most serious threats to public health and the environment in Indian country that are not otherwise being adequately addressed. Further, EPA encourages and will work closely with all tribes wishing to develop TIPs for approval under the Tribal Authority Rule. EPA intends that its federal regulations created through a FIP will apply only in those situations in which a tribe does not have an approved TIP.

4. EPA Authority

a. <u>General authority to issue part 71 permits</u>

Title V of the Clean Air Act requires that EPA promulgate, administer, and enforce a federal operating permits program when a state does not submit an approvable program within the time frame set by title V or does not adequately administer and enforce its EPA-approved program. On July 1, 1996 (61 FR 34202), EPA adopted regulations codified at 40 CFR part 71 setting forth the procedures and terms under which the Agency would administer a federal operating permits program. These regulations were updated on February 19, 1999 (64 FR 8247) to incorporate EPA's approach for issuing federal operating permits to stationary sources in Indian country.

As described in 40 CFR 71.4(a), EPA will implement a part 71 program in areas where a state, local, or tribal agency has not developed an approved part 70 program. Unlike states, Indian tribes are not required to develop operating permits programs, though EPA encourages tribes to do so. See, e.g., Indian Tribes: Air Quality Planning and Management (63 FR 7253, February 12, 1998) (also known as the "Tribal Authority Rule"). Therefore, within Indian country, EPA will administer and enforce a part 71 federal operating permits program for stationary sources until a tribe receives approval to administer their own operating permits program.

5. Use of All Credible Evidence

Determinations of deviations, continuous or intermittent compliance status, or violations of the permit are not limited to the testing or monitoring methods required by the underlying regulations or this permit; other credible evidence (including any evidence admissible under the Federal Rules of Evidence) must be considered by the source and EPA in such determinations.

6. Public Participation

a. <u>Public notice</u>

As described in 40 CFR 71.11(a)(5), all part 71 draft operating permits shall be publicly noticed and made available for public comment. The Public Notice of permit actions and public comment period is described in 40 CFR 71(d).

There will be a 30 day public comment period for actions pertaining to a draft permit. Public notice will be given for this draft permit by mailing a copy of the notice to the permit applicant, the affected state, tribal and local air pollution control agencies, the city and county executives, the state and federal land managers and the local emergency planning authorities which have jurisdiction over the area where the source is located. A copy of the notice will be provided to all persons who have submitted a written request to be included on the mailing list. If you would like to be added to our mailing list to be informed of future actions on these or other Clean Air Act permits issued in Indian country, please send your name and address to the contact listed below:

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

Public notice will be published in the Durango Herald as detailed in the cover letter of this permit package, giving opportunity for public comment on the draft permit and the opportunity to request a public hearing.

b. Opportunity for Comment

Members of the public will be given an opportunity to review a copy of the draft permit prepared by EPA, the application, this statement of basis for the draft permit, and all supporting materials for the draft permit. Copies of these documents are available at:

La Plata County Clerk's Office
1060 East 2nd Avenue
Durango, Colorado 81302

and

Southern Ute Indian Tribe
Environmental Programs Office
116 Mouache Drive
Ignacio, Colorado 81137

and

US EPA Region 8
Air Program Office
1595 Wynkoop Street (8P-AR)
Denver, Colorado 80202

All documents are available for review at the U.S. EPA Region 8 office Monday through Friday from 8:00 a.m. to 4:00 p.m. (excluding federal holidays).

Any interested person may submit written comments on the draft part 71 operating permit during the public comment period to the Part 71 Permit Contact at the address listed above. All comments would have to be considered and answered by EPA in making the final decision on the permit. EPA keeps a record of the commenters and of the issues raised during the public participation process.

Anyone, including the applicant, who believes any condition of the draft permit is inappropriate should raise all reasonable ascertainable issues and submitted all arguments supporting their position by the close of the public comment period. Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has been already submitted as part of the administrative record in the same proceeding or consists of state or federal statutes and regulations, EPA documents of general applicability, or other generally available reference material.

c. Opportunity to Request a Hearing

A person may submit a written request for a public hearing to the Part 71 Permit Contact, at the address listed above, by stating the nature of the issues to be raised at the public hearing. Based on the number of hearing requests received, EPA will hold a public hearing whenever it finds there is a significant degree of public interest in a draft operating permit. EPA will provide public notice of the public hearing. If a public hearing is held, any person may submit oral or written statements and data concerning the draft permit.

d. Appeal of permits

Within 30 days after the issuance of a final permit decision, any person who filed comments on the draft permit or participated in the public hearing may petition to the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments or participate in the public hearing may petition for administrative review, only if the changes from the draft to the final permit decision or other new grounds were not reasonably foreseeable during the public comment period. The 30 day period to appeal a permit begins with EPA's service of the notice of the final permit decision.

The petition to appeal a permit must include a statement of the reasons supporting the review, a demonstration that any issues were raised during the public comment period, a demonstration that it was impracticable to raise the objections within the public comment period, or that the grounds for such objections arose after such a period. When appropriate, the petition may include a showing that the condition in question is based on a finding of fact or conclusion of law which is clearly erroneous; or, an exercise of discretion, or an important policy consideration which the Environmental Appeals Board should review.

The Environmental Appeals Board will issue an order either granting or denying the petition for review, within a reasonable time following the filing of the petition. Public notice of the grant of review will establish a briefing schedule for the appeal and state that any interested person may file an amicus brief. Notice of denial of review will be sent only to the permit applicant and to the person requesting the review. To the extent review is denied, the conditions of the final permit decision become final agency action.

A motion to reconsider a final order shall be filed within 10 days after the service of the final order. Every motion must set forth the matters claimed to have been erroneously decided and the nature of the alleged errors. Motions for reconsideration shall be directed to the Administrator rather than the Environmental Appeals Board. A motion for reconsideration shall not stay the effective date of the final order unless it is specifically ordered by the Board.

e. Petition to reopen a permit for cause

Any interested person may petition EPA to reopen a permit for cause, and EPA may commence a permit reopening on its own initiative. EPA will only revise, revoke and reissue, or terminate a permit for the reasons specified in 40 CFR 71.7(f) or 71.6(a)(6)(i). All requests must be in writing and must contain facts or reasons supporting the request. If EPA decides the request is not justified, it will send the requester a brief written response giving a reason for the decision. Denial of these requests is not subject to public notice, comment, or hearings. Denials can be informally appealed to the Environmental Appeals Board by a letter briefly setting forth the relevant facts.

f. Notice to affected states/tribes

As described in 40 CFR 71.11(d)(3)(i), public notice will be given by mailing a copy of the notice to the air pollution control agencies of affected states, tribal and local air pollution control agencies which have jurisdiction over the area in which the source is located, the chief executives of the city and county where the source is located, any comprehensive regional land use planning agency and any state or federal land manager whose lands may be affected by emissions from the source. The following entities will be notified:

State of Colorado, Department of Public Health and Environment
State of New Mexico, Environment Department
Southern Ute Indian Tribe, Environmental Programs Office
Ute Mountain Ute Tribe, Environmental Programs
Navajo Tribe, Navajo Nation EPA
Jicarilla Tribe, Environmental Protection Office
La Plata County, County Clerk
Town of Ignacio, Mayor
National Park Service, Air, Denver, CO
U.S. Department of Agriculture, Forest Service, Rocky Mountain Region
San Juan Citizen Alliance
Carl Weston
Rocky Mountain Clean Air Action

United States Environmental Protection Agency
Region VIII
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 1/4, SW 1/4 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 VIII

Date

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AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE

BP America Production Company
Florida River Compression Facility

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

Issue Date:
Effective Date:
Expiration Date:

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
TBD	1st Renewal Issued		Permit # V-SU-0022-05.00

TABLE OF CONTENTS

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
NOx	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

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 Lat. 37-09-23.0 Long. -107-46-50

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 2922 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 NOx 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.

The potential to emit for the facility as a whole are as follows:

Nitrogen Oxides (NOx) – 282.07 tpy
Carbon Monoxide (CO) – 181.94 tpy
Volatile Organic Compounds (VOC) – 30.27 tpy
Small Particulates (PM_{10}) – 7.95 tpy
Sulfur Dioxide (SO_2) – 24.23 tpy
Total Hazardous Air Pollutants (HAPs) – 4.14 tpy
Largest Single HAP (formaldehyde, CH_2O) – 1.20 tpy

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: 0690-H Installed: 1995	None
T-2	45 MMBtu/hr Solar Centaur H T5700 Turbine. Natural gas fired, simple cycle: Serial Number: 0307-H 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% NOx 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 -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
1 - 300 gal Diesel Tank
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 Specific Units

Certain requirements in section II of this permit (specifically, conditions II.A.2. and II.A.3., II.B., II.C., II.D.7. through II.D.10., II.E.3., II.E.4., and II.E.5., II.F.1. and II.F.3.)have been created, at the permittee's request, specifically to recognize the selective catalytic reduction systems for limiting the PTE of nitrogen oxide (NOx) emissions from the electric generating units.

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

II.A. Emission Standards and Limits

[40 CFR part 60, subpart GG and 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 NOx standard and the sulfur dioxide (SO_2) fuel standard listed in Table 3 below.

Table 3 - Turbine Emission Standards

Pollutant	Emission Standard	Regulatory Reference
NOx	$STD = 0.0150\frac{(14.4)}{Y} + F = 174$ ppm where Y= 12.4 kilojoules per watt hour (manufacturer's rated heat rate at manufacturer's rated peak load) and F = 0 (NOx emission allowance for fuel bound nitrogen) and STD = allowable NOx 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)

2. Cumulative NOx 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 not exceed 39.1 tons during any consecutive 12 months.

3. 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.

4. Each electric generating unit is considered in shutdown mode if the unit runs less than 30 minutes per quarter. *[Explanatary 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) Condition II.B.9. – Fuel sulfur content limit.
(ii) *Conditions II.E.3., II.E.4., II.E.5.(a) and (b), II.E.6.(c), and II.E.8.* – Record keeping requirements and calculation of rolling 12-month emissions.
(iii) Conditions II.E.1.(c) and II.E.3. – Reporting requirements

(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 II.C., when a unit is taken out of shut-down mode or operates for 30 minutes or more per quarter.

II.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 NOx.

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. 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 II.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 NOx 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.)

7. 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.

   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 NOx 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.

8. The permittee's completion of any or all of the actions prescribed by conditions II.B.6.(a) through (c) and II.B.7 of this permit shall not constitute, nor qualify as, an exemption from the NOx emission limit in this permit.

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

II.C. <u>Testing Requirements</u> [40 CFR 71.6(a)(3)(i)(A) through (C)]

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 NOx emissions to demonstrate compliance with the cumulative emission limit in section II.A.2. The initial performance test for NOx 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 NOx emissions from the unit to demonstrate compliance cumulative emission limit in section II.A.2. The performance test for NOx 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 NOx 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 NOx emissions.

5. All tests for NOx 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 NOx 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 NOx 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).

II.D. <u>Monitoring Requirements</u> [40 CFR 60.334(b)(2) and 40 CFR 71.6(a)(3)(i)(A) through (C)]

1. 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 NOx 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.

2. 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 as required by 40 CFR 60.334.

3. 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.

4. 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.

5. 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.1.(a)(iii) of this permit shall govern nitrogen content monitoring and section II.D.1.(b)(iv) of this permit shall govern sulfur content monitoring.

6. The permittee shall measure NOx 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 NOx 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).

7. The permittee shall measure NOx emissions from three (3) of the 12 diesel fired electric generating units per quarter to demonstrate compliance with the cumulative NOx emission limit in section II.A.2. above. Each of the electric generating units must be monitored for NOx emissions at least once during a calendar year. To meet this requirement, the permittee shall measure the NOx 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 NOx 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 NOx to EPA.

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

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

10. 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.

II.E. <u>Recordkeeping Requirements</u> [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)]

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

    (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.

(c) The permittee shall comply with the following recordkeeping requirements when firing an emergency fuel in turbine units T-1 and T-2:

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

2. 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.

3. At the end of the calendar month following the NOx initial performance tests, individual and cumulative NOx 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 NOx performance tests required in condition II.C.1. These emissions calculations shall be recorded.

Subsequent to the initial calculation, individual and cumulative NOx 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.

4. The NOx 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 NOx quarterly monitoring test result for that generating unit by the number of operating hours for that generating unit for that calendar month;

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

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

   (a) Records shall be kept of all temperature measurements required by sections II.C.4. and II.D.8. of this permit, as well as a description of any corrective actions taken pursuant to section II.B.6. of this permit.

   (b) Records shall be kept of all pressure drop measurements required by sections II.C.4. and II.D.9. of this permit, as well as a description of any corrective actions taken pursuant to section II.B.7. of this permit.

   (c) Records shall be kept that are sufficient to demonstrate, pursuant to section II.B.9. of this permit, that the maximum sulfur content of the diesel fuel fired in the electric generating units has not exceeded 0.5 percent.

   (d) 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 specified in section II.B.4. of this permit.

6. The permittee shall keep records of all required monitoring in section II.D. of 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.

7. 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 63.774(d)(1)]

II.F. **<u>Reporting Requirements</u>** [40 CFR 71.6(a)(3)(iii).]

1. The permittee shall submit to EPA a written report of the results of the NOx performance tests and temperature and pressure drop measurements required in section II.C. of 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 III.B.1. a report of any instances where an SCR system inlet temperature deviates from the acceptable range listed in condition II.B.5. and where the pressure drop across an SCR system deviates from the acceptable reading listed in condition II.B.7., as well as a description of any corrective actions taken pursuant to II.B.6. and II.B.7. If no such instances have been detected, then a statement shall be provided to say so.

II.G. **<u>General Provisions of NSPS</u>** [See 40 CFR part 60, subpart A and 60.11(d)]

1. At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practices 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 is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

2. This source is subject to the entire text of 40 CFR, part 60, subpart A, including, but not limited to, the following sections:

Section	Description
60.1	Applicability
60.2	Definitions
60.3	Units and abbreviations
60.4(a)	Address
60.5	Determination of construction or modification
60.6	Review of plans
60.7	Notification and record keeping
60.8	Performance tests
60.9	Availability of information
60.11	Compliance with standards and maintenance requirements
60.12	Circumvention
60.14	Modification
60.15	Reconstruction
60.17	Incorporations by reference
60.19	General notification and reporting requirements

III. 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)]

III.A. General 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 federally recognized 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 at the Operations Center for a period of five 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 condition IV.Q, of off-permit changes made in accordance with the approved Alternative Operating Scenarios.

III.B General Reporting Requirements [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 IV.F.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 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 continue for more than two 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 II.F.4.(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 IV.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 condition II.F.2.

[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]

III.C. <u>Chemical Accident Prevention</u> [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 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.

III.D. <u>Alternative Operating Scenarios</u> - 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 IV.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.

III.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, 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 IV.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 II.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 III.D and III.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 (condition IV.I of this permit) shall be utilized to maintain the permitted emission limits of the replaced engine and/or incorporate the new applicable requirements.]

III.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 or;

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

IV. Part 71 Administrative Requirements

IV.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;

[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)]

IV.B. <u>Annual Emissions Inventory</u> [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.]

IV.C. <u>Compliance Requirements</u> [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 Clean Air Act 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 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 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)]

IV.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)]

IV.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: <u>http://www.epa.gov/air/oaqps/permits/p71forms.html</u>]

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

IV.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.

IV.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.

IV.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.]

IV.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 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 section IV.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)]

IV.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 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 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) does not extend to group processing of minor permit modifications.

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

IV.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)]

IV.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.

IV.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.

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

IV.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 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.

IV.P. <u>Transfer of Ownership or Operation</u> [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.

IV.Q. <u>Off Permit Changes</u> [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 Clean Air Act;

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 <u>(per the definitions in 40 CFR 60.2, 60.4230(a), and 63.2)</u>, 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
        (iv) 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 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) 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 <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 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.

IV.R. <u>Permit Expiration and Renewal</u> [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)]

V. Appendix

V.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

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.

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

V.C. Portable Analyzer Monitoring Protocol and Approval - Attached

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

DEC -2 1996

Ref: 8ENF-T

Mr. Richard Duarte
El Paso Natural Gas
3801 Atrisco Blvd., NW
Albuquerque, NM 87120

RECEIVED DEC 11 1996 ENVIRONMENTAL AFFAIRS

Dear Mr. Duarte:

This is in response to your November 8, 1996 request for a custom fuel monitoring schedule (CFMS) for El Paso Natural Gas Company's Florida River Compressor Station, Units 1 & 2, located in La Plata County, Colorado. El Paso Natural Gas Company also requested to be allowed to use gas chromatograph monitoring for Phase I and the "Length of Stain Tube" test for Phases II and III for measuring the sulfur content of the natural gas to be burned in the turbines.

Florida River's Units 1 & 2 are subject to 40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines. The custom fuel monitoring schedule for sulfur content, proposed by El Paso, meets the custom sampling schedule set forth for approval in an August 14, 1987 memorandum signed by John B. Rasnic with EPA's Compliance Monitoring Branch. Therefore, EPA Region VIII approves your proposed CFMS for your Florida River's Units 1 & 2.

Your request for the use of a gas chromatograph monitoring system for measuring the natural gas sulfur content falls under the authority of Section 60.13(i) of 40 CFR as a request for alternative monitoring to replace the specified ASTM test methods. According to the tariff specifications in El Paso's gas transmission contracts, the natural gas received from suppliers is limited to approximately 0.0025 weight percent sulfur. This is far below the allowable sulfur content of 0.8 percent. Based on that, the use of El Paso's gas chromatograph monitoring system is sufficient to be used to determine the natural gas sulfur content, and therefore, is approved for use during Phase I sampling at your Florida River's Units 1 & 2. Should the sulfur content of the fuel approach the regulatory limit, EPA reserves the right to revisit this decision.

El Paso also requested the use of the "Length of Stain Tube" test for Phase II and III under the CFMS. In an April 26, 1991 memo from William G. Laxton, Director of the U.S. Environmental Protection Agency's Technical Support Division, the "Length of Stain Tube" test used to test for sulfur in natural gas was determined to be an acceptable alternative test provided that the sulfur content of the fuel gas is well below the 0.8 percent

Subpart GG standard. Since El Paso's fuel gas is low in sulfur, EPA Region VIII agrees to your use of the "Length of Stain Tube" test for Phases II & III for monitoring the sulfur content of the natural gas.

If you have any questions concerning our approval of your custom fuel monitoring schedule, the use of your gas chromatograph as an alternative monitoring procedure or the use of the "Length of Stain Tube" test, you may call Cindy Reynolds of my staff (303) 312-6206.

Sincerely,

Martin Hestmark

Martin Hestmark, Director
Technical Enforcement Program

cc: Jim Geier, CDPHE

EL PASO NATURAL GAS
3801 Atrisco Blvd., NW
Albuquerque, NM 87120

November 8, 1996

Martin Hestmark, Director
Technical Enforcement Program
US EPA Region 8
999 18th Street, Suite 500
Denver, Colorado 80202-2466

CERTIFIED MAIL
RETURN RECEIPT REQUESTED
P 591 541 749

Re: Custom Fuel Monitoring Schedule request for El Paso Natural Gas Company's ("El Paso") Florida River Compressor Station, La Plata County, Colorado.

Dear Mr. Hestmark:

El Paso submits this request for a custom fuel monitoring schedule ("CFMS") for the referenced compressor station. The proposed CFMS demonstrates continuous compliance by incorporating the following:

- El Paso's constant gas quality monitoring system required by the Federal Energy Regulatory Commission ("FERC"); and,
- Segments of a previously approved EPA schedule using the length-of-stain technique.

El Paso presently operates under a tariff, approved by the FERC, which contains more stringent sulfur specifications than the EPA standard in § 60.333.

By combining the FERC-required monitoring with portions of the EPA-approved schedule, the proposed CFMS helps to fulfill one of the main directives in the President's Regulatory Reinvention Initiative for the EPA. In short, the proposed protocol reduces unnecessary reporting and monitoring while at the same time maintaining a high level of environmental protection for the nation.

El Paso believes the proposed CFMS is amenable and appropriate. We would be glad to meet with you to discuss this protocol further and to assist in your review. If you should have any questions, please contact me at 505/831-7763.

Very truly yours,

Richard Duarte

Richard Duarte
Sr. Environmental Engineer
Compliance Services

Enclosure (Florida River CFMS)

Copy (with enclosure):

CERTIFIED MAIL
RETURN RECEIPT REQUESTED
P 591 541 750

James S. Geier, P.E., Chief
Permit Section
Stationary Sources Program -- Air Pollution Control Division
Colorado Department of Public Health & Environment
4300 Cherry Creek Drive South
Denver, Colorado 80222-1530

EL PASO NATURAL GAS

Custom Fuel Monitoring Schedule
for

Florida River Compressor Station

Table of Contents

EL PASO NATURAL GAS

Custom Fuel Monitoring Schedule
for
Florida River Compressor Station

1.0 Introduction.

El Paso Natural Gas Company ("El Paso") provides pipeline-quality natural gas transportation services for natural gas suppliers and end users throughout the Southwestern United States. EPNG owns and operates a large pipeline network for which Florida River Compressor Station ("Florida River") is one of many stations that provide natural gas compression. The amount of pipeline quality natural gas transported in the system varies depending on customer demand for natural gas. Compression is needed to maintain enough pressure in the pipeline to make required deliveries to customers. Compression at Florida River is accomplished by two simple-cycle natural gas-fired turbines that drive compressor units. This compressor station is automated and therefore is an unattended location.

The two turbines currently operate under Colorado Department of Health and Environment Air Pollution Control Division's (CDH&E) Permit No. 95LP423 and 90LP014-2 (see Appendix A). The monitoring requirements listed under Florida River's air permits require fuel monitoring, and thus the purpose of this Custom Fuel Monitoring Schedule.

El Paso had initially submitted its request for a Custom Fuel Monitoring Schedule (CFMS) for this facility on December 13, 1994. However, the request had erroneously been submitted to EPA's Region 6 office. The plan was returned to El Paso on August 15, 1996, (which noted the submittal mix-up). In the interim, El Paso developed a different CFMS from that one proposed in 1994, which was recently submitted to Region 6 for turbine facility in Northwestern New Mexico. The enclosed plan and that one submitted to Region 6 are identical (in monitoring protocol) and were adapted from EPA-approved custom schedules for natural gas fueled turbines in the gas transportation industry. Thus the enclosed schedule is more detailed than the one submitted in 1994 and demonstrates continuous compliance with NSPS Subpart GG, specifically Title 40 CFR §60.332 and §60.333.

2.0 Title 40 CFR §60.332 (nitrogen oxides) and §60.333 (sulfur oxides) Applicability.

The station comprises two Solar Centaur Type H turbines. The Centaur's peak load is 5,500 hp (14.56 Gigajoules/hr). Therefore, both turbines are included by the standards (greater than 10.7 Gigajoules/hr) in Subpart GG, specifically at §60.330(a). Accordingly, the monitoring requirements of the Florida River CFMS are applicable to both turbines (El Paso reference: Florida River Unit Numbers 1 & 2).

This proposed CFMS demonstrates continuous compliance by incorporating El Paso's constant gas quality monitoring system required by the Federal Energy Regulatory Commission ("FERC") and segments of an EPA-approved schedule using the length-of-stain ("LOS") technique. El Paso operates under a tariff approved by the FERC that establishes strict specifications for the sulfur content of the natural gas delivered by El Paso. Therefore, the gas received from suppliers is continuously monitored by El Paso at strategic locations at or very near receipt points to ensure compliance with the tariff specifications. A small portion of this gas is then used to fuel the various natural gas-fired engines used throughout the pipeline system, which includes Florida River. The pertinent sections of the tariff sheet are enclosed for your reference in Appendix B.

3.0 Nitrogen Monitoring Protocol.

3.1 Overview. In general, nitrogen monitoring is not necessarily required, unless fuel sources other than pipeline-quality natural gases are used. Therefore, this nitrogen monitoring protocol is specific to those conditions when non-pipeline-quality natural gas is used as fuel.

3.2 Nitrogen monitoring has been excluded as a requirement from the air permit. In brief, the motives for deleting this requirement are:

a. the nitrogen content of pipeline quality natural gas (and correspondingly the fuel that is used) does not vary significantly like other fuels often used by turbines;
b. El Paso is not taking fuel-bound nitrogen credits; and,
c. free nitrogen does not contribute appreciably to NO_x emissions.

Therefore, the primary focus of the monitoring protocol is chiefly on sulfur content. A copy of Florida River's permits are in Appendix C.

3.3 Regardless of the above, the following CFMS is an alternative to the monitoring requirements contained in §60.334(b)(2).

a. Monitoring of fuel nitrogen content shall **not be required** while pipeline-quality natural gas is the only fuel fired in the gas turbine. This includes use of a bulk storage tank(s) whose source is pipeline-quality natural gas.
b. Monitoring of fuel nitrogen content shall be determined and 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).
c. Should a nitrogen analysis, required for any reason other than firing an emergency fuel, demonstrate noncompliance with 40 CFR §60.332, El Paso shall immediately notify the CDH&E Air Pollution Control Division ("CDH&E") and the US EPA of the excess emissions, and the CFMS shall be re-examined by the CDH&E and EPA. Nitrogen monitoring shall be conducted daily during the interim period when this CFMS is being re-examined.

d. If there is a change in fuel supply, El Paso will immediately notify the CDH&E and EPA of such change for re-examination of the CFMS. For purposes of this CFMS, it is understood subtle changes or variations in fuel quality occur. These variations or changes are specific heating values, gas composition (methane, ethane, propane, isobutane, isopentane, n-pentane and hexanes) and inert gases, as allowed by El Paso's tariff. A change in fuel supply shall therefore be considered a change in the supply **apart from** pipeline-quality natural gas. Nitrogen monitoring shall be conducted daily during the interim period when this CFMS is being re-examined.

4.0 Sulfur Monitoring Protocol.

4.1 Overview. As its monitoring protocol, El Paso is proposing to use a combination of its natural gas quality monitors, which it is obligated to maintain under its FERC tariff, and EPA's Length-of-stain ("LOS") technique. Sulfur monitoring is proposed in three separate monitoring periods or phases (I, II and III).

Briefly, in the first phase, El Paso is proposing to utilize its 35-year operational knowledge of gas quality produced in the San Juan Basin and current gas quality measurements to replace the EPA's *traditional* phase I LOS alternative. Phase I of this protocol will serve to minimize duplication of effort, unnecessary paperwork and more importantly reduce personnel burdens for El Paso, CDH&E and EPA. Phases II and III are derived from previously approved EPA protocols.

4.2. Gas Quality Measurement System.

Overview. El Paso maintains, at a minimum three types of continuously operating gas quality monitors at strategic locations at or very near receipt points. The purpose of these monitors is to ensure that on a continuous basis "sweet" pipeline-quality natural gas is always in the pipeline as required by the FERC tariff. The tariff specifications are in turn written into El Paso's gas transmission contracts, which ensure a minimum quality (not solely for H_2S) of all natural gas received from and delivered to any customer. Accordingly as specified in the tariff sheets (on Original Sheet No. 220, Section 5.1(c)), natural gas received from suppliers is limited to total sulfur content of 5 grains/100 standard cubic feet. Reference Appendix B. This amount is equivalent to approximately 0.0025 weight percent sulfur, well below the 0.8 percent limit within Subpart GG.

These monitors may perform a gas analysis for the following components (individually or in select combinations): hydrogen sulfide (H_2S), total sulfur, nitrogen (N_2), carbon dioxide (CO_2), heat value, hydrocarbon content and specific gravity. These continuous composite samplers are either two types of automated gas chromatographs ("GC"), or H_2S-lead acetate tape analyzers ("H_2S analyzers") with data processing resulting in a versatile instrument system that can be adapted to a wide array of analysis methods. The two type of GCs used within the system either monitor solely for sulfur content (H_2S & organic sulfur) or hydrocarbons and other inert gases. The basic components of these three continuous composite samplers are the automatic injection system, chromatography column or lead acetate tape, sensor, controls and communications connector. Sample gas is intermittently injected auotmatically through a chromatographic column or exposed to lead acetate tape in an H_2S analyzer.

Gas Chromatography of H_2S & Hydrocarbons

The chromatography column is a Teflon tube packed with an adsorbent material that separates the sample gas into its constituents by adsorption and then elution. Each constituent adsorbs for a finite period of time that is determined by the molecular weight and structure of the constituent compound. Thus, the adsorption and elution period are a predictable characteristic of each individual compound and can be programmed into the memory of the integrator or timed by the operator for identification purposes.

In normal operation of a sulfur-monitoring GC, nitrogen is used as the inert carrier gas which travels constantly through the column and into the sensor. This sample cycle normally takes 30 minutes. The carrier gas for the hydrocarbon-monitoring GC is helium. The sampling cycle for a hydrocarbon GC takes approximately 4 minutes. During the injection sequence, sample flow is diverted briefly to the sample loop and then is flushed from the sample loop into the column, where sulfur compounds and other gases are adsorbed. Flow of the carrier gas causes elution of sample components that are separated according to their affinity for the adsorbent material in the column. With some constituents this separation is almost immediate. This process exposes the natural gas constituents to an electrochemical sensor. Sulfur compounds in the sample react with the electrolyte in the sensor that causes a detectable current proportional to sulfur concentration. GCs that are designated for hydrocarbon-quality monitoring sample once every 4 minutes. Whereas, GCs designated for sulfur compounds sample the natural gas stream once every 30 minutes. These values are then averaged once every 24-hours to attain a daily average.

H_2S Analyzers

The H_2S analyzer operation is chiefly a quantitative analysis based on the classic lead acetate test for hydrogen sulfide. The procedure consists of exposing a piece of lead acetate to the gas stream. Any H_2S in the gas stream reacts with the lead acetate on the tape turning it varying shades of brown, depending on the H_2S concentration. The measuring portion of the H_2S analyzer consists of two photocells coupled to a millivolt recorder. Each photocell unit contains a lamp and optical filter. One photocell is the reference while the other serves for measuring the exposed stream. This produces a differential in millivolt output between the photocells. The difference is translated into an H_2S concentration value.

These H_2S analyzers are typically placed at receipt points where "sour gas" fields supply the natural gas treatment plants, which in turn deliver treated pipeline quality natural gas onto El Paso's pipeline network. In the New Mexico San Juan producing basin, El Paso operates only one H_2S analyzer. This is due to El Paso's 35-year operation in this producing area. In contrast, within the "sour" gas producing fields of the West Texas Permian Basin, El Paso maintains well over 70 H_2S Analyzers.

GC and Rubicon Quality Control

GCs and H_2S analyzers are checked by trained and skilled technicians. H_2S analyzers and GCs are inspected for general operation once every week. H_2S analyzers are manually calibrated once every month and GCs once every quarter. However, all GCs auto-verify at a preset time every day. The verification process consists of flowing a gas through the GC with known concentrations and checking the response factor and retention time. If these calculated values are within acceptable tolerances, the GC continues operation. Whenever, a verification fails an alarm is sent to El Paso's Gas Control Center (manned 24-hrs per day) and the equipment is checked and re-calibrated. Manual inspection includes reviewing the general operation of the systems and, at minimum, includes the inspection of temperature sensors, gas flow paths (sample line and purge line), recording devices, communication system and housekeeping.

Calibration on a GC consists of challenging the system with known concentrations of NIST traceable gases per manufacturer procedures. At a minimum, hydrocarbon monitoring GCs are calibrated monthly (verified daily, however); and, sulfur monitoring GCs are calibrated at least once every six months (also verified daily). The sensitivity is rated at 0.1 mg sulfur per cubic meter of gas (approximately 0.1 ppm H_2S). The GC's repeatability is $\pm$ 5%.

An H_2S analyzer is challenged monthly with tile standards that have been verified with concentrations of NIST traceable gas at a concentrations of less than or equal to 0.25 grains of H_2S. Accuracy for these systems is $\pm$ 0.5% of calibrated range.

GC and Rubicon Operation

The real-time information from any GC is monitored continuously, and if it exceeds 75% of H_2S tariff grain standard, an alarm is sent to El Paso's Gas Control Center. Once again, sulfur-monitoring GCs are typically installed where multiple and combined gas streams can be monitored. These sulfur-monitoring GCs are not used at or near the reciept point where H_2S is not produced with the natural gas and historically has never been a problem for El Paso. Such is the case at Florida River. An H_2S analyzer is not required at the inlet natural gas stream at Florida River because in El Paso's 35-year history of transporting this gas, it has been known as "sweet" from the point of production. The GC monitoring Florida River's sulfur content of the natural gas stream is down-stream of the station (based on El Paso's experience in this production area). The data from this GC is included in Appendix C. This GC monitors the combined natural gas streams from three other sources (including gas from Florida River). The sole GC monitor upstream of Florida River only monitors hydrocarbon content and inert gases. It does not monitor sulfur compounds since it has never been a source problem. As a matter of fact, El Paso had operated an sulfur monitoring GC immediately downstream of Florida River for an estimated 10 years. The readings never exceeded zero for H_2S, so El Paso discontinued its use in 1992.

An H_2S analyzer functions more independently than a GC. All data is recorded on a chart recorder and any alarms or valve shut-ins are immediately sent to El Paso's Gas Control Center. Typically, the analyzers are set to "alarm" at 0.20 grains and shut-in the valve at 0.25 grains. Whenever a valve is, shut-in, gas flow is immediately stopped from the treatment plant, and El Paso then notifies the natural gas treating plant. If a gas limit is exceeded, the gas treating plant operator must correct the H_2S problem before El Paso resets the slam valve and begins receiving pipeline-quality natural gas again. El Paso has only one H_2S analyzer in the San Juan Basin pipeline transportation system and connected to a gathering system downstream, and apart from, the gas flowing from Florida River. This is entirely based on El Paso's 35-year experience in the basin.

4.3 Sulfur Monitoring.

a. Analysis of fuel Sulfur content of the gas turbine (natural gas or any other type of fuel) shall be conducted using the appropriate methods specified in 40 CFR §60.3~~6~~35(d).; or,
3
b. For Phase I sampling only, use El Paso's GC monitoring system for daily sulfur; See Appendix C, for the proposed Phase I data.
c. Under Phases II and III, the "length of stain tube" method is approved as an alternative fuel sulfur test method for this CFMS, providing that the Gas Processors Association (GPA) procedures are followed and 100% pipeline quality natural gas is the only fuel fired in the gas turbines. (GPA Standard 2377-86).
d. Monitoring of fuel sulfur content shall be determined and recorded daily while firing an emergency fuel as defined in 40 CFR. §60.331(r).

Effective the date of this CFMS, the sampling and analysis frequency of fuel sulfur allowed under this CFMS fuel schedule is as follows:

PHASE	**FREQUENCY**	**TECHNIQUE**	**PERIOD**
I	Daily	El Paso's GC Data	Six months *(data included)*
II	Quarterly	LOS	Eighteen months
III	Semi-annually	LOS	Two years

If, during the period of each phase, this monitoring shows little variability in the fuel sulfur content and demonstrates continuous compliance with the emission limits for sulfur dioxide contained in 40 CFR §60.333, the company may then proceed to the next sampling phase with written notice to the CDH&E and EPA.

e. Should a sulfur analysis, required for any reason other than for firing emergency fuel, demonstrate non-compliance with the emission limits for Sulfur Dioxide contained in 40 CFR §60.333, the owner or operator shall immediately notify the CDH&E and EPA of such excess emissions and sulfur monitoring shall be conducted daily during the interim period while this CFMS is being re-examined.

f. If there is a change in fuel supply, the owner or operator must notify the CDH&E and EPA of such change for re-examination of this CFMS. A change in fuel quality, fuel makeup or fuel supplier shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted daily during the interim period when this CFMS is being re-examined.

4.4 General Provisions

a. Approval of this CFMS is based on the application submitted El Paso, dated November 8, 1996, for the firing of 100% pipeline-quality natural gas. Any change in any representation made by the company in this application shall cause this CFMS to be suspended and re-examined by the CDH&E and EPA. CDH&E and EPA shall be notified immediately if any such change occurs.
b. All analyses required by this custom schedule shall be performed by a laboratory using the approved test methods, except for Phase I testing using El Paso's GC and Phases II and III using the LOS.
c. The company may request that EPA allow for the substitution of any analytical method for another method specified in this CFMS. Any substitution will require the written approval of the EPA.
d. CDH&E and the EPA may request that an audit of the fuel sampling program be conducted at any time during the life of this custom 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, paragraphs 3.3 (c) and/or 4.3 (d) shall govern.
e. Records of sample analysis, fuel supplier, fuel supply, fuel quality, and fuel make-up pertinent to this custom schedule shall be retained for a period of two years, and made available for inspection by personnel of federal, state and local air pollution control agencies.
f. After the initial four year term of the CFMS, the custom schedule will continue using the same monitoring, record-keeping and notification requirements as stipulated in Phase III of the schedule. However, the

CDH&E and the EPA may choose to terminate the CFMS and require the company to reapply for a CFMS. Termination of the CFMS will require that the company begin as required by 40 CFR SS 60.334.

g. Date of issuance ______________________. The contents of this shall be implemented no later than 30-days from date of issuance. The effective start date shall be noted on all documents required by Phases II and III.

h. Records required by the sulfur monitoring protocol will be maintained at El Paso Natural Gas Company's Albuquerque Division Office, 3801 Atrisco Blvd., NW, Albuquerque, New Mexico 87120.

Last page of plan

First Revised Sheet No. 10

Superseding Original Sheet No. 10

Preliminary Statement

PRELIMINARY STATEMENT

El Paso Natural Gas Company, hereinafter referred to as "El Paso" is a "natural gas company" as defined by the Natural Gas Act (52 Stat. 821, 15 U.S.C. 717–717w) and, as such, is subject to the jurisdiction of the Federal Energy Regulatory Commission, hereinafter referred to as "FERC" or "Commission." As used herein, "El Paso" shall not include any of El Paso's affiliates.

El Paso's jurisdictional sales for resale operations are described in the Preliminary Statement contained in Volume No. 1 of El Paso's FERC Gas Tariff.

El Paso is in the business of providing jurisdictional transportation services to or for others as an open–access transporter under authority of Part 284 of the Commission's Regulations pursuant to written contracts containing or incorporating by reference terms and conditions which are acceptable to El Paso. El Paso also provides jurisdictional transportation services on behalf of various **shippers** pursuant to pre–existing individual contracts which were entered into prior to the effective date of this Volume No. 1–A FERC Gas Tariff. Said pre–existing individual contracts, insofar as they provide for transportation services other than those open–access services which El Paso has agreed to provide under authority of Part 284 of the Commission's Regulations, have and will continue, after the effective date of the Volume No. 1–A FERC Gas Tariff, to be included as special rate schedules in El Paso's Volume No. 2 FERC Gas Tariff. El Paso specifically disclaims any undertaking on its part to provide service as a common or public carrier of **natural gas** or other goods for hire. Services which El Paso may provide under compulsion of emergency circumstances involving public or private need or of governmental directive shall not serve to constitute El Paso a common or public carrier of natural gas or other goods for hire.

This FERC Gas Tariff is filed in compliance with Part 154, Subchapter E, Chapter I, Title 18, of the Code of Federal Regulations.

Issued by: Patricia A. Shelton, Vice President
Issued on: November 28, 1995
Effective: January 01, 1996
Issued to comply with order of the Federal Energy Regulatory Commission, Docket No. CP94–183–000 and 001, dated SEPTEMBER 13, 1995

First Revised Sheet No. 10

Superseding Original Sheet No. 10

Preliminary Statement

PRELIMINARY STATEMENT

El Paso Natural Gas Company, hereinafter referred to as "El Paso" is a "natural gas company" as defined by the Natural Gas Act (52 Stat. 821, 15 U.S.C. 717–717w) and, as such, is subject to the jurisdiction of the Federal Energy Regulatory Commission, hereinafter referred to as "FERC" or "Commission." As used herein, "El Paso" shall not include any of El Paso's affiliates.

El Paso's jurisdictional sales for resale operations are described in the Preliminary Statement contained in Volume No. 1 of El Paso's FERC Gas Tariff.

El Paso is in the business of providing jurisdictional transportation services to or for others as an open–access transporter under authority of Part 284 of the Commission's Regulations pursuant to written contracts containing or incorporating by reference terms and conditions which are acceptable to El Paso. El Paso also provides jurisdictional transportation services on behalf of various **shippers** pursuant to pre–existing individual contracts which were entered into prior to the effective date of this Volume No. 1–A FERC Gas Tariff. Said pre–existing individual contracts, insofar as they provide for transportation services other than those open–access services which El Paso has agreed to provide under authority of Part 284 of the Commission's Regulations, have and will continue, after the effective date of the Volume No. 1–A FERC Gas Tariff, to be included as special rate schedules in El Paso's Volume No. 2 FERC Gas Tariff. El Paso specifically disclaims any undertaking on its part to provide service as a common or public carrier of **natural gas** or other goods for hire. Services which El Paso may provide under compulsion of emergency circumstances involving public or private need or of governmental directive shall not serve to constitute El Paso a common or public carrier of natural gas or other goods for hire.

This FERC Gas Tariff is filed in compliance with Part 154, Subchapter E, Chapter I, Title 18, of the Code of Federal Regulations.

Issued by: Patricia A. Shelton, Vice President
Issued on: November 28, 1995
Effective: January 01, 1996
Issued to comply with order of the Federal Energy Regulatory Commission, Docket No. CP94–183–000 and 001, dated SEPTEMBER 13, 1995

Original Sheet No. 200

Transportation General Terms and Conditions

Issued by: A. W. Clark, Vice President
Issued on: May 23, 1994
Effective: July 01, 1994

Original Sheet No. 220

Transportation General Terms and Conditions (Continued)

5. QUALITY

5.1 All natural gas received by El Paso at any mainline Receipt Point(s) shall conform to the following specifications and must be, in El Paso's reasonable judgment, otherwise merchantable:

(a) Liquids – The gas shall be free of water and hydrocarbons in liquid form at the temperature and pressure at which the gas is received. The gas shall in no event contain water vapor in excess of seven (7) pounds per million standard cubic feet.

(b) Hydrocarbon Dew Point – The hydrocarbon dew point of the gas received shall not exceed twenty degrees Fahrenheit (20°F) at normal pipeline operating pressures.

(c) Total Sulfur – The gas shall not contain more than five (5) grains of total sulfur per one hundred (100) standard cubic feet, which includes hydrogen sulfide, carbonyl sulfide, carbon disulfide, mercaptans, and mono–, di– and poly–sulfides. The gas shall also meet the following individual specifications for hydrogen sulfide, mercaptan sulfur or organic sulfur:

(i) Hydrogen Sulfide – The gas shall not contain more than one–quarter (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet.

(ii) Mercaptan Sulfur – The mercaptan sulfur content shall not exceed more than three–quarters (0.75) grain per one hundred (100) standard cubic feet.

(iii) Organic Sulfur – The organic sulfur content shall not exceed one and one–quarter (1.25) grains per one hundred (100) standard cubic feet, which includes mercaptans, mono–, di– and poly–sulfides, but it does not include hydrogen sulfide, carbonyl sulfide or carbon disulfide.

(d) Oxygen – The oxygen content shall not exceed two–tenths of one percent (0.2%) by volume and every reasonable effort shall be made to keep the gas delivered free of oxygen.

Issued by: A. W. Clark, Vice President
Issued on: May 23, 1994
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Example Calculations & Fuel Analyses

The table below is representative of a typical fuel-gas analysis for the Rio Vista station. Gas chromatograph analysis results for nitrogen, carbon dioxide, and hydrocarbons (methane,"C1", through hexane+, "C6+") are reported on a percent molar basis. Hydrogen sulfide ("H_2S") and total organic sulfur ("TOS") results are generally reported in units of "grains per 100 standard cubic feet" (or "gr/100 scf"). The majority of the TOS measurement consists of mercaptans mono-sulfide, di-sulfide, and poly-sulfide.

Component	Mole Percent	gr / 100 scf	Molecular Weight	Mole % * MW	Weight Percent
Nitrogen	0.244	-	28.013	0.068	0.383
Carbon Dioxide	0.806	-	44.010	0.355	1.997
Methane	92.723	-	16.043	14.876	83.695
Ethane	3.640	-	30.070	1.095	6.161
Propane	1.524	-	44.097	0.672	3.781
ISO-Butane	0.253	-	58.123	0.147	0.827
N-Butane	0.380	-	58.123	0.221	1.243
ISO-Pentane	0.134	-	72.150	0.097	0.546
N-Pentane	0.103	-	72.150	0.074	0.416
Hexane +	0.193	-	86.177	0.166	0.934
Hydrogen Sulfide	0.0004	0.250	34.082	0.0001	0.0006
Total Organic Sulfur	0.0035	5.000	77.000	0.0027	0.0152
TOTAL	**100.00**			**17.774**	**100.00**

To convert a sulfur compound grain measurement "grains of H2S or TOS per 100 standard cubic feet " to a weight basis, the following methodology is used:

1. Calculate the weight of total sulfur in 100 SCF of gas.

$$\left(\frac{\text{grains } H_2S \text{ or TOS}}{}\right) \times \left(\frac{1.0 \text{ lb}}{7000 \text{ grains}}\right) \times \left(\frac{(\text{MW of Sulfur}) \text{ lbs}}{(\text{MW of} H_2S \text{ or TOS})\text{lbs}}\right) = \text{lbs of Sulfur in 100 scf of gas.}$$

Note: the sum of elemental sulfur in H_2S and TOS should equal the total sulfur in 100 SCF of fuel gas.

2. Calculate the total weight of 100 SCF of fuel gas:

$$\left(\frac{100 \text{ SCF of fuel gas}}{}\right) \times \left(\frac{1 \text{ lb-mol fuel gas}}{379 \text{ SCF}}\right) \times \left(\frac{(\text{average MW of fuel gas}) \text{ lbs}}{\text{lb-mol of fuel gas}}\right) = \text{lbs of 100 SCF of gas}$$

3. Weight percent of sulfur is calculated by:

$$\left(\frac{\text{lbs of Sulfur in 100 SCF of gas}}{\text{lbs of 100 SCF of fuel gas}}\right) \times 100 = \text{Wt \% of Sulfur in fuel}$$

For example, to convert 0.25 grains / 100 scf of hydrogen sulfide (assume TOS = 0.0 grains):

$$\left(\frac{0.25 \text{ grains } H_2S}{}\right) \times \left(\frac{\text{lb}}{7000 \text{ grains}}\right) \times \left(\frac{32 \text{ lbs of Sulfur}}{34 \text{ lbs of } H_2S}\right) = 0.000034 \text{ lbs of Sulfur in 100 SCF}$$

Next, calculate the weight of 100 SCF of fuel gas:

$$\left(\frac{\text{100 SCF of fuel gas}}{}\right) \times \left(\frac{\text{1 lb-mol fuel gas}}{\text{379 SCF}}\right) \times \left(\frac{17.774 \text{ lbs}}{\text{lb-mol of fuel gas}}\right) = 4.69 \text{ lbs of 100 SCF of gas}$$

Next, calculate the weight percent of sulfur:

$$\left(\frac{0.000034 \text{ lbs of sulfur}}{4.69 \text{ lbs fuel gas}}\right) \times 100 = 0.0007\ \%$$

<u>NOTE</u>: At standard conditions (generally, "60°F" and "14.73 psia" for the natural gas transportation industry), the molar specific volume of any ideal gas, v, is approximately 379 scf/lb-mol. This value is calculated using the ideal gas law,

$$v = \left(\frac{R_u \times T}{P}\right)$$

where:

- v = molar specific volume, ft^3/ lb-mol [scf / lb-mol]
- R_u = universal gas constant, 10.73164 psia•ft^3 / (lb-mol•°R)
- T = standard temperature, °R
- P = standard pressure, psia

Total Organic Sulfur, or TOS, is derived from the odorant (mercaptan) contained in the gas transported by El Paso. Where necessary, El Paso may inject varing amounts of mercaptan to ensure minimum levels are delivered to customers.