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ENGINEERING EVALUATION / FACT SHEET

BACKGROUND INFORMATION

Application No.:	R13-2831C
Plant ID No.:	051-00130
Applicant:	Appalachia Midstream Services, L.L.C. (AMS)
Facility Name:	Miller Compressor Station
Location:	Bannen, Marshall County
NAICS Code:	211111
Application Type:	Modification
Received Date:	September 14, 2011
Engineer Assigned:	Jerry Williams II, P.E.
Fee Amount:	$2,000.00
Date Received:	September 14, 2011
Complete Date:	November 18, 2011
Due Date:	February 16, 2012
Applicant Ad Date:	September 21, 2011, September 26, 2011
Newspaper:	*Wetzel Chronicle*, *Moundsville Daily Echo*
UTM's:	Easting: 532.48 km Northing: 4396.73 km Zone: 17
Description:	Installation of five (5) additional compressor engines each equipped with an oxidation catalyst (EUCE-7 – EUCE-11), and one (1) glycol dehydration unit with still vent controlled by an air cooled condenser (EUDHY-3). Increase in the hourly limitation of the 805 HP Capstone C600 Microturbine Generator (EPGEN-2) from 500 hours per year to 8,760 hours per year. This permitting action also revises emission calculations from the existing glycol dehydration units using a recent extended gas analysis. Storage tank emissions were also updated to reflect the most current emissions based on working, breathing, and flashing losses. Greenhouse gas emissions were included in the engineering evaluation to reflect that this source was minor for PSD purposes.

DESCRIPTION OF PROCESS

The following process description was taken from Permit Application R13-2831C:

The natural gas inlet stream from surrounding area wells enters the facility through an inlet suction separator prior to the gas being compressed. After the inlet gas passes through a compressor, it goes through the dehydration process before exiting the facility. Triethylene glycol (TEG) dehydration units are used to remove water from the gas. In the dehydration process, gas passes through a contactor vessel where water is absorbed by the glycol. The "rich" glycol containing water goes to the glycol reboiler where heat is used to boil off the water. The heat is supplied by a natural gas-fired reboiler that exhausts to the atmosphere. Overhead still column emissions will be controlled by an air-cooled condenser. The non-condensables from the still column emissions overheads will be routed to the reboiler and burned as fuel with 95% destruction efficiency. Under normal operating circumstances, flash tank overhead vapors will be routed to the reboiler to be burned as fuel with 95% destruction efficiency. Any excess flash gas vapors not burned as fuel will be routed to the stabilizer feed drum. During upset conditions, excess flash gas may be routed to the flare and combusted with 98% destruction efficiency. Upset conditions include loss of both permanent and backup power or compressor malfunction of the primary and secondary flash gas compressors.

Collected liquids are stabilized to remove volatile components before being stored in the ten (10) 400 bbl condensate storage tanks and transported off-site by truck. Overhead vapors generated in the stabilizer are compressed by an electric-driven flash gas compressor and recycled to the inlet gas stream. The hot oil heater provides hot oil to the stabilizer. Condensate dropout from liquids dumps, produced water and other pipeline fluids are stored in the two (2) 400-bbl pipeline fluids/water storage tanks and transported off-site via truck. A Joule-Thomson (JT) system with a capacity of less than 10 mmscfd will be used to lower the heat content of the fuel gas.

The generators provide electric power to the flash gas compressor, glycol pumps, hot oil pumps and other electrical equipment. Gas glycol pumps may also be used in place of the electric glycol pumps. The flare is used to combust gas during upsets and may also be used to combust flash tank off-gas and condensate stabilizer overhead gas as needed during flash gas compressor shutdown or maintenance. Emissions from fugitive components also occur.

SITE INSPECTION

A compliance inspection was conducted by Steve Sobutka of the DAQ NPRO Enforcement Section on August 23, 2011. They are currently operating in compliance.

Directions as given in the permit application are as follows:

From Bannen, head southwest on Amos Hollow Road/County Road 89 toward Clark Hill for 1.1 miles. Turn left at Laurel Run. In 0.8 miles, turn right to stay on Laurel Run. In 0.4 miles, take slight left at Johnson Hill. Take the first left onto County Road 1/22/Johnson Ridge.

ESTIMATE OF EMISSIONS BY REVIEWING ENGINEER

Emissions associated with this modification application consist of the combustion emissions from the five (5) proposed compressor engines (EUCE-7 – EUCE-11), one (1) glycol dehydration unit (EUDHY-3), revised truck loading emissions (EU-LOAD), and revised glycol dehydration unit emissions (EUDHY-1, EUDHY-2).

Each TEG dehydration unit is equipped with a primary electric glycol pump with a maximum capacity of 15 gallons per minute. In addition, each glycol dehydration unit has two (2) gas injection glycol pumps, each with a maximum capacity of 7.5 gallons per minute. Potential VOC emissions were based on GRI-GlyCalc results for the electric pumps since the emissions were higher than those using the backup gas pumps. Potential greenhouse gas (GHG) emissions were based on the GRI-GlyCalc results for the gas pumps since those emissions were higher than using the electric pump. Still vent vapors from the glycol dehydration units are controlled by an air-cooled condenser. Non-condensables from the still column overheads are routed to the reboiler and burned with a 95% destruction efficiency. Under normal operating circumstances, flash tank overhead vapors are routed to the reboiler to be burned as fuel. Any excess vapors not burned as fuel are routed to the flash gas suction scrubber for 100% control efficiency. During upset conditions, excess flash gas may be routed to the flare and combusted with 98% control efficiency. Upset conditions include loss of both permanent and backup power or compressor malfunction of the primary and secondary flash gas compressors.

Truck loading emissions were calculated using AP-42 for Petroleum Liquid Loading Losses and the physical properties of the liquids loaded obtained from a site specific liquids analysis.

Fugitive emissions for the facility are based on calculation methodologies presented in the 2009 American Petroleum Institute Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry. The factors presented in the API Compendium are for methane emissions. Therefore, the fugitive VOC and HAP emissions were calculated using a representative gas analysis and the weight percent of each respective pollutant.

Maximum controlled point source emissions from the revised changes were calculated by AMS and checked for accuracy by the writer and only the changes associated with this modification application are summarized in the table below.

Emission Point ID	Emission Unit ID	Process Unit	Pollutant	Maximum Controlled Emission Rate	
				Hourly (lb/hr)	Annual (ton/year)
EPCE-7	EUCE-7	1,380 HP Caterpillar G3516B Compressor Engine	Nitrogen Oxides	1.52	6.66
			Carbon Monoxide	1.52	6.66
			Sulfur Dioxide	0.03	0.14
			Particulate Matter-10	0.11	0.49
			Volatile Organic Compounds	0.67	2.93
			Formaldehyde	0.29	1.28
			Total HAPs	0.34	1.50
			Carbon Dioxide Equivalent	1,537.67	6,734.99
EPCE-8	EUCE-8	1,380 HP Caterpillar G3516B Compressor Engine	Nitrogen Oxides	1.52	6.66
			Carbon Monoxide	1.52	6.66
			Sulfur Dioxide	0.03	0.14
			Particulate Matter-10	0.11	0.49
			Volatile Organic Compounds	0.67	2.93
			Formaldehyde	0.29	1.28
			Total HAPs	0.34	1.50
			Carbon Dioxide Equivalent	1,537.67	6,734.99
EPCE-9	EUCE-9	1,380 HP Caterpillar G3516B Compressor Engine	Nitrogen Oxides	1.52	6.66
			Carbon Monoxide	1.52	6.66
			Sulfur Dioxide	0.03	0.14
			Particulate Matter-10	0.11	0.49
			Volatile Organic Compounds	0.67	2.93
			Formaldehyde	0.29	1.28
			Total HAPs	0.34	1.50
			Carbon Dioxide Equivalent	1,537.67	6,734.99

EPCE-10	EUCE-10	1,380 HP Caterpillar G3516B Compressor Engine	Nitrogen Oxides	1.52	6.66
			Carbon Monoxide	1.52	6.66
			Sulfur Dioxide	0.03	0.14
			Particulate Matter-10	0.11	0.49
			Volatile Organic Compounds	0.67	2.93
			Formaldehyde	0.29	1.28
			Total HAPs	0.34	1.50
			Carbon Dioxide Equivalent	1,537.67	6,734.99
EPCE-11	EUCE-11	1,380 HP Caterpillar G3516B Compressor Engine	Nitrogen Oxides	1.52	6.66
			Carbon Monoxide	1.52	6.66
			Sulfur Dioxide	0.03	0.14
			Particulate Matter-10	0.11	0.49
			Volatile Organic Compounds	0.67	2.93
			Formaldehyde	0.29	1.28
			Total HAPs	0.34	1.50
			Carbon Dioxide Equivalent	1,537.67	6,734.99
EPGEN-2	EUGEN-2	805 HP Capstone C600 Microturbine Generator	Nitrogen Oxides	0.25	1.09
			Carbon Monoxide	0.56	2.46
			Sulfur Dioxide	0.02	0.09
			Particulate Matter-10	0.05	0.20
			Volatile Organic Compounds	0.01	0.06
			Formaldehyde	0.01	0.02
			Total HAPs	0.01	0.03
			Carbon Dioxide Equivalent	800.31	3,501.94
EPSTL-1	EUDHY-1	53.8 MMscfd Glycol Dehydrator Still Column	Volatile Organic Compounds	0.75	3.26
			Total HAPs	0.22	0.96
			Benzene	0.05	0.21
			Toluene	0.11	0.47
			Xylenes	0.05	0.20
			n-Hexane	0.02	0.08
			Carbon Dioxide Equivalent	2.25	9.86

EPRBL-1	EUDHY-1	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Nitrogen Oxides	0.10	0.44
EPRBL-1	EUDHY-1	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Carbon Monoxide	0.08	0.35
EPRBL-1	EUDHY-1	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Sulfur Dioxide	0.01	0.01
EPRBL-1	EUDHY-1	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Particulate Matter-10	0.01	0.05
EPRBL-1	EUDHY-1	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Volatile Organic Compounds	0.01	0.04
EPRBL-1	EUDHY-1	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Carbon Dioxide Equivalent	117.00	512.48
EPSTL-2	EUDHY-2	53.8 MMscfd Glycol Dehydrator Still Column	Volatile Organic Compounds	0.75	3.26
EPSTL-2	EUDHY-2	53.8 MMscfd Glycol Dehydrator Still Column	Total HAPs	0.22	0.96
EPSTL-2	EUDHY-2	53.8 MMscfd Glycol Dehydrator Still Column	Benzene	0.05	0.21
EPSTL-2	EUDHY-2	53.8 MMscfd Glycol Dehydrator Still Column	Toluene	0.11	0.47
EPSTL-2	EUDHY-2	53.8 MMscfd Glycol Dehydrator Still Column	Xylenes	0.05	0.20
EPSTL-2	EUDHY-2	53.8 MMscfd Glycol Dehydrator Still Column	n-Hexane	0.02	0.08
EPSTL-2	EUDHY-2	53.8 MMscfd Glycol Dehydrator Still Column	Carbon Dioxide Equivalent	2.25	9.86
EPRBL-2	EUDHY-2	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Nitrogen Oxides	0.10	0.44
EPRBL-2	EUDHY-2	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Carbon Monoxide	0.08	0.35
EPRBL-2	EUDHY-2	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Sulfur Dioxide	0.01	0.01
EPRBL-2	EUDHY-2	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Particulate Matter-10	0.01	0.05
EPRBL-2	EUDHY-2	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Volatile Organic Compounds	0.01	0.04
EPRBL-2	EUDHY-2	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Carbon Dioxide Equivalent	117.00	512.48
EPSTL-3	EUDHY-3	53.8 MMscfd Glycol Dehydrator Still Column	Volatile Organic Compounds	0.75	3.26
EPSTL-3	EUDHY-3	53.8 MMscfd Glycol Dehydrator Still Column	Total HAPs	0.22	0.96
EPSTL-3	EUDHY-3	53.8 MMscfd Glycol Dehydrator Still Column	Benzene	0.05	0.21
EPSTL-3	EUDHY-3	53.8 MMscfd Glycol Dehydrator Still Column	Toluene	0.11	0.47
EPSTL-3	EUDHY-3	53.8 MMscfd Glycol Dehydrator Still Column	Xylenes	0.05	0.20
EPSTL-3	EUDHY-3	53.8 MMscfd Glycol Dehydrator Still Column	n-Hexane	0.02	0.08
EPSTL-3	EUDHY-3	53.8 MMscfd Glycol Dehydrator Still Column	Carbon Dioxide Equivalent	2.25	9.86
EPRBL-3	EUDHY-3	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Nitrogen Oxides	0.10	0.44
EPRBL-3	EUDHY-3	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Carbon Monoxide	0.08	0.35
EPRBL-3	EUDHY-3	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Sulfur Dioxide	0.01	0.01
EPRBL-3	EUDHY-3	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Particulate Matter-10	0.01	0.05
EPRBL-3	EUDHY-3	1.00 MMBTU/hr Glycol Dehydrator Reboiler	Volatile Organic Compounds	0.01	0.04

			Carbon Dioxide Equivalent	117.00	512.48
EPTK-1 – EPTK-12	EUTK-1 – EUTK-12	Twelve (12) 400 bbl Storage Tanks	Volatile Organic Compounds	NA	7.24
			Total HAPs	NA	0.25
			Carbon Dioxide Equivalent	0.01	35.75

The following table represents the total facility emission increase:

Pollutant	Maximum Annual Facility Wide Emissions Before R13-2831C (tons/year)	Maximum Annual Facility Wide Emissions After R13-2831C (tons/year)	Net Change (tons/year)
Nitrogen Oxides	44.13	77.98	33.85
Carbon Monoxide	57.57	91.88	34.31
Volatile Organic Compounds	26.70	54.45	27.75
Particulate Matter	5.94	8.45	2.51
Sulfur Dioxide	0.96	1.66	0.70
Formaldehyde	2.04	8.44	6.40
Total HAPs	7.81	15.31	7.50
Carbon Dioxide Equivalent	40,738.85	78,241.47	37,502.62

The following table indicates the control device efficiencies that are required for this facility:

Emission Unit	Pollutant	Control Device	Control Efficiency
EPCE-1 – EPCE-6 Compressor Engines	Nitrogen Oxides	Non Selective Catalytic Reduction (NSCR)	96.50 %
	Carbon Dioxide		93.25 %
	Volatile Organic Compounds		84.50 %
	Hazardous Air Pollutants		50.00 %
EPCE-7 – EPCE-11 Compressor Engines	Carbon Monoxide	Oxidation Catalyst	83.00 %
	Volatile Organic Compounds		70.00 %
	Hazardous Air Pollutants		76.00 %
EUDHY-1 – EUDHY-3 Glycol Dehydration Units	BTEX (Benzene, Toluene, Ethylbenzene, Xylene)	Condenser/Combustion	99.70 %
	Volatile Organic Compounds		99.70 %
EPTK-1 – EPTK-12 Storage Tanks	Volatile Organic Compounds	Vapor Recovery Unit	98.00 %
EPLOR Loadout Rack	Volatile Organic Compounds	Closed System	100.00 %

REGULATORY APPLICABILITY

Unless otherwise stated WVDEP DAQ did not determine whether the permittee is subject to an area source air toxics standard requiring Generally Achievable Control Technology (GACT) promulgated after January 1, 2007 pursuant to 40 CFR 63, including the area source air toxics provisions of 40 CFR 63, Subpart HH and 40 CFR 63, Subpart ZZZZ.

The following rules apply to the changes requested in this modification application:

45CSR2 (Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers)

The purpose of 45CSR2 (Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers) is to establish emission limitations for smoke and particulate matter which are discharged from fuel burning units.

45CSR2 classifies the added reboiler (EPRBL-3) as a ‘type b’ unit. The allowable PM emission rate for the reboiler (EPRBL-3) would be the product of 0.09 and the total design heat input of each of the reboiler (1.00 MMBTU/hr). This equates to a maximum allowable PM emission rate of 0.09 lb/hr. According to AMS’s permit application, the proposed PM emission rate is 0.01 lb/hr. Therefore, this standard should be met.

AMS also would be subject to the opacity requirements in 45CSR2, which is 10% opacity based on a six minute block average.

45CSR4 (To Prevent and Control the Discharge of Air Pollutants into the Open Air which Causes or Contributes to an Objectionable Odor or Odors)

45CSR4 states that an objectionable odor is an odor that is deemed objectionable when in the opinion of a duly authorized representative of the Air Pollution Control Commission (Division of Air Quality), based upon their investigations and complaints, such odor is objectionable. No odors have been deemed objectionable.

45CSR10 (To Prevent and Control Air Pollution from the Emissions of Sulfur Oxides)

The purpose of this rule is to establish standards for emissions of sulfur oxides from fuel burning units, manufacturing operations and gas streams.

45CSR10 classifies the added reboiler (EPRBL-3) as a ‘type b’ unit. The allowable SO_2 emission rate for the reboiler (EPRBL-3) would be the product of 0.09 and the total design heat input of the reboiler (1.00 MMBTU/hr). This equates to a maximum allowable SO_2 emission rate of 0.09 lb/hr. According to AMS’s permit application, the proposed SO_2 emission rate is 0.01 lb/hr. Therefore, this standard should be met. Furthermore, 45CSR10A exempts fuel burning units that combust natural gas from testing and monitoring requirements.

45CSR13 (Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, and Procedures for Evaluation)

45CSR13 applies to this source due to the fact that the changes proposed under this permitting action results in an emissions increase above modification thresholds. Therefore, AMS is required to submit a modification application. AMS has published the required Class I legal advertisement notifying the public of their permit application, and paid the appropriate application fee (modification).

45CSR16 (Standards of Performance for New Stationary Sources Pursuant to 40 CFR Part 60)

45CSR16 applies to this source by reference of, 40CFR60, Subpart KKK, and 40CFR60, Subpart JJJJ. AMS is subject to the recordkeeping, monitoring, and testing required by 40CFR60, Subpart KKK, 40CFR60, Subpart VV, and 40CFR60, Subpart JJJJ.

45CSR30 (Requirements for Operating Permits)

This permit does not affect 45CSR30 applicability. The source is a nonmajor source subject to 45CSR30 and is classified as a deferred source.

40CFR60 Subpart JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines)

AMS's compressor engines are subject to 40CFR60 Subpart JJJJ, which sets forth emission limits, fuel requirements, installation requirements, and monitoring requirements based on the year of installation of the subject internal combustion engine. 40CFR60 Subpart JJJJ is applicable to owners and operators of new stationary spark ignition internal combustion engines manufactured after July 1, 2007, for engines with a maximum rated power capacity greater than 500 hp.

The five (5) proposed 1,380 hp engines (EPCE-7 – EPCE-11) will be subject to this rule. The emission limits for these engines are the following: NOx – 2.0 g/hp-hr (3.55 lb/hr); CO – 4.0 g/hp-hr (7.09 lb/hr); and VOC – 1.0 g/hp-hr (1.77 lb/hr). Based on the manufacturer's specifications for these engines, the emission standards should be met.

Because these engines will not be certified by the manufacturer, AMS will be required to perform an initial performance test within 180 days from startup, and subsequent testing every 8,760 hours or 3 years, whichever comes first.

The following rules do not apply to the facility:

40CFR60 Subpart Kb (Standards of Performance for VOC Liquid Storage Vessels)

40CFR60 Subpart Kb does not apply to storage vessels with a capacity less than 75 cubic meters. The tanks that AMS has proposed to install are 63.84 cubic meters each. Therefore, they would not be subject to this rule.

45CSR14 (Permits for Construction and Major Modification of Major Stationary Sources of Air Pollutants)

45CSR19 (Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution which Cause or Contribute to Nonattainment)

As shown in the table below, AMS is not subject to 45CSR14 or 45CSR19 review.

Pollutant	**PSD (45CSR14) Threshold (tpy)**	**NANSR (45CSR19) Threshold (tpy)**	**Miller PTE (tpy)**	**45CSR14 or 45CSR19 Review Required?**
Carbon Monoxide	250	NA	91.88	No
Nitrogen Oxides	250	100	77.98	No
Sulfur Dioxide	250	100	1.66	No
Particulate Matter 2.5	250	100	8.45	No
Ozone (VOC)	250	NA	54.45	No
Greenhouse Gas (CO_2e)	100,000	NA	78,241.47	No

40CFR63 Subpart ZZZZ (National Emission Standards for Reciprocating Ignition Internal Combustion Engines)

40CFR63 Subpart HH (National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and National Emission Standards for Hazardous Air Pollutants: Natural Gas Transmission and Storage)

WVDEP DAQ did not determine whether the permittee is subject to an area source air toxics standard requiring Generally Achievable Control Technology (GACT) promulgated after January 1, 2007 pursuant to 40 CFR 63, including the area source air toxics provisions of 40 CFR 63, Subpart HH and 40 CFR 63, Subpart ZZZZ.

These promulgated national emission standards for hazardous air pollutants (NESHAP) limit emissions of hazardous air pollutants (HAP) from oil and natural gas production and natural gas transmission and storage facilities. These final rules implement section 112 of the Clean Air Act (Act) and are based on the Administrator's determination that oil and natural gas production and natural gas transmission and storage facilities emit HAP identified on the EPA's list of 188 HAPs.

TOXICITY OF NON-CRITERIA REGULATED POLLUTANTS

There will be small amounts of various non-criteria regulated pollutants emitted from the combustion of natural gas. However, due to the concentrations emitted, detailed toxicological information is not included in this evaluation.

AIR QUALITY IMPACT ANALYSIS

Modeling was not required of this source due to the fact that the facility is not subject to 45CSR14 (Permits for Construction and Major Modification of Major Stationary Sources of Air Pollutants) as seen in the table listed in the Regulatory Discussion Section.

SOURCE AGGREGATION

"Building, structure, facility, or installation" is defined as all the pollutant emitting activities which belong to the same industrial grouping, are located on one or more contiguous and adjacent properties, and are under the control of the same person.

1. The Miller Compressor Station will operate under SIC code 1311 (Crude Petroleum and Natural Gas Extraction). There are surrounding wells and compressor stations that share the same two-digit major SIC code of 13 for oil and gas exploration and production. Other natural gas compressor stations in the area are operated by AMS and have the same two-digit major SIC code. The unique nature of oil and gas operations links many operations by pipeline in order to create operational flexibility and provide customers with multiple delivery options. Therefore, the Miller Compressor Station does share the same SIC code as the wells and surrounding compressor stations.

2. The Miller Compressor Station will be located approximately 3 miles from the existing Pleasants Compressor Station. "Contiguous or Adjacent" determinations are made on a case by case basis. These determinations are proximity based, and it is important to focus on this and whether or not it meets the common sense notion of a plant. The terms "contiguous" or "adjacent" are not defined by USEPA. Contiguous has a dictionary definition of being in actual contact; touching along a boundary or at a point. Adjacent has a dictionary definition of not distant; nearby; having a common endpoint or border.

   The Miller Compressor Station is not located contiguous with or adjacent to any well site or any other compressor station in the area. The nearest well to the Miller Compressor Station is approximately 1 mile away. It is anticipated that the Miller Compressor Station will be able to gather gas from wells located over 20 miles away. Additionally, the nearest compressor station is located approximately three miles away. Operations separated by these distances do not meet the common sense notion of a plant. Therefore, the properties in question are not considered to be on contiguous or adjacent property.

3. According to AMS, none of the wells in the area are under common control with the Miller Compressor Station. The Miller Compressor Station is operated by AMS but is owned and controlled by a group of non-affiliated companies. Through the proprietary

agreement, AMS' operation of the Miller Compressor Station is controlled by the system owners. The ownership and control of the wells in the area may be distinct for each well and is not necessarily known by AMS. The owners and operators of the wells each make their own operational decisions about the wells independently and without any control by AMS. Furthermore, no well is dependent on the operation of the Miller Compressor Station to function, nor is the Miller Compressor Station dependent on any specific well to operate. While well site operations are affected by the operation of the Miller Compressor Station, the owners and operators of each well have the ability to pipe the well to other compressor stations. However, since AMS does not own or operate any wells in the area, AMS does not control how a well is operated. AMS does operate and control other compressor stations in the area.

Because the facilities are not considered to be on contiguous or adjacent properties and are not fully under control of the same person, the emissions from the Miller Compressor Station should not be aggregated with other facilities in determining major source or PSD status.

MONITORING OF OPERATIONS

AMS will be required to perform the following monitoring associated with this modification application:

1. Monitor and record quantity of natural gas consumed for all engines, and combustion sources.
2. Monitor all applicable requirements of 40CFR60 Subparts JJJJ.

AMS will be required to perform the following recordkeeping associated with this modification application:

1. Maintain records of the amount of natural gas consumed in each combustion source.
2. Maintain records of testing conducted in accordance with the permit. Said records shall be maintained on-site or in a readily accessible off-site location
3. Maintain the corresponding records specified by the on-going monitoring requirements of and testing requirements of the permit.
4. Maintain records of the visible emission opacity tests conducted per the permit.
5. Maintain a record of all potential to emit (PTE) HAP calculations for the entire facility. These records shall include the natural gas compressor engines and ancillary equipment.
6. The records shall be maintained on site or in a readily available off-site location maintained by AMS for a period of five (5) years.
7. Maintain records of all applicable requirements of 40CFR60 Subparts JJJJ.

CHANGES TO PERMIT R13-2831B

AMS made several proposed changes in Permit Application R13-2831C. The following is a summary of the changes to the current permit:

1. Installation of five (5) additional 1,380 HP Caterpillar G3516B engines equipped with oxidation catalysts (EPCE7-11).
2. Installation of one (1) additional TEG dehydration unit equipped with condenser controls (EPSTL-3, EPRBL-3).
3. Increase in the hourly limitation of the 805 HP Capstone C600 Microturbine Generator (EPGEN-2) from 500 hours per year to 8,760 hours per year.
4. Emission calculations from the existing glycol dehydration units were revised using a recent extended gas analysis.
5. Storage tank emissions were updated to reflect the most current emissions based on working, breathing, and flashing losses. Greenhouse gas emissions were included in the engineering evaluation to reflect that this source was minor for PSD purposes.

In addition, AMS proposed to remove the requirement that the Liquids Truck Loading (EU-LOAD) be a closed system. This requirement ensures that this operation is a closed system which results in 100% control efficiency with zero emissions. Upon review of the proposed requirement, the DAQ will not approve the removal of this requirement.

RECOMMENDATION TO DIRECTOR

The information provided in the permit application indicates AMS's Miller Compressor Station meets all the requirements of applicable regulations. Therefore, impact on the surrounding area should be minimized and it is recommended that the Marshall County location should be granted a 45CSR13 modification permit for their facility.

Jerry Williams, P.E.
Engineer

Date