ENGINEERING ANALYSIS

PERMITTING HISTORY

On December 2, 2024, the Department received a permit application from Ventex Operating Corporation for the ATIC 34-12 No. 1 Oil and Gas Production Facility (34-12 Well). The well is located at SW/4 of Section 34, Township 4 North, Range 7 East, in Conecuh County, Alabama. The well was expected to process approximately 400 thousand standard cubic feet per day (MScf/day) of gas resulting in 146 million Scf (MMScf) per year of natural gas and 400 barrels (bbl) of oil per day (146,000 bbl per year). Air Permit No. 103-0046-X001 was issued for this project on February 14, 2025.

Based on production data (gas analysis completed on May 7, 2025), after the well began production, Ventex determined that the well was capable of producing a maximum of 852 MScf/day of natural gas (310.98 MMScf/yr) and 675 barrels of oil per day (246,375 bbl per year). Due to the increase in production from what the facility was originally permitted, Ventex reduced its production rate at the well until a gas plant could be constructed and the gas could be processed and sold rather than burned in the facility flare as originally designed. The permit application for this project was received at the Department on July 16, 2025. A complete application was received on October 2, 2025. The Barnett Plant was constructed to remove the water from the gas, process the gas to drop out the natural gas liquids (NGLS), and remove hydrogen sulfide (H_2S) from the gas produced at the ATIC 34-12 Well. The plant was located on contiguous property a few feet from the entrance of the production well, and it was owned and operated by Ventex.

The ATIC 34-12 production well is currently equipped with the following emissions sources:

- 0.5 million British thermal unit (MMBtu) per hour (hr) heater treater (HT-01)
- Process Flare (FL-01) with closed vent system (CVS)
- Four (4), 400-barrel (bbl) condensate storage vessel
- One (1), 500 bbl power oil storage vessel
- One (1), 400 bbl saltwater storage vessel
- Inlet separator and low-pressure separator
- Vapor Recovery Unit (VRU) with closed vent system (CVS)

The following equipment along with associated fugitive components are located at the Barnett Plant adjacent to the 34-12 Well.

- 202 HP (150 kilowatts (kW)), Caterpillar, Model No. 3306B, four stroke, rich burn, spark ignition compressor engine (ENG-01) equipped with non-selective catalytic reduction (NSCR/3-way catalyst). The associated compressor will be a reciprocating compressor.
- Fugitive emission components associated with the addition of the gas plant
- JT refrigeration skid
- Sulfa Treat Tower consisting of two pressure vessels
- Water knockout vessel
- 30,000 gallon, pressurized NGL storage tank

DRAFT

On March 1, 2026, Pruet Production Company (Pruet) acquired the ATIC 34-12 Well and Barnett Plant from Ventex Operating Corporation. On March 20, 2026, Synthetic Minor Operating Permit (SMOP) No.: 103-0046-X001 was issued to Pruet.

PROJECT DESCRIPTION

On July 10, 2026, Pruet submitted a permit application to the Department, requesting to add the proposed ATIC 33-8 Oil and Gas Production Well (33-8 Well) which will be located in Section 33, Township 4 North, Range 7 East, in Conecuh County, AL. The proposed well will be within 1 mile of the existing ATIC 34-12 Well and Barnett Plant. As a result, these combined emissions sites will be referred to as Barnett Area 1 as requested by Pruet.

The proposed oil and gas production rate for the proposed ATIC 33-8 Well was based on the monthly production rate for the existing ATIC 34-12 Well. Pruet indicated that the proposed well is estimated to produce 700 barrels of oil per day (bbl/d) and 1,025,000 standard cubic feet of natural gas per day (Scf/day) (~1,025 MScf/day). Since the proposed well will be located in the same reservoir as the ATIC 34-12 Well, Pruet estimates that the gas will have a heat value of 1,107 British thermal units per Scf (BTU/Scf) and the H_2S content in the gas will be 12 parts per million (ppmv). Once the proposed well is tested, estimated emissions will be revised as needed.

The proposed ATIC 33-8 Well will consist of the following emission sources:

- 0.5 million British thermal unit (MMBtu) per hour (hr) heater treater (HT-02)
- High pressure and low-pressure separators
- Process Flare (FL-02) with closed vent system (CVS)
- Four (4), 400-barrel (bbl) condensate storage vessel
- One (1), 500 bbl power oil storage vessel
- One (1), 400 bbl saltwater storage vessel
- Closed vent system (CVS) that collects all tank gas vapors

PROCESS DESCRIPTION

The gas produced at the proposed well will be burned in the facility flare until the construction of the gathering line that will route the gas from the proposed well to the existing ATIC 34-12 Well. All gas will be collected via the closed vent system and vapor recovery unit (VRU) and routed to the Barnett Plant via the existing gathering pipeline. At the plant, the gas will be sweetened by a Sulfa-Treat Tower which will remove any traces of H_2S from the gas. The sweetened natural gas (high Btu gas) will be processed to drop out any heavy hydrocarbon liquids in the gas using the Joule-Thompson (JT) unit. Natural gas liquids (NGLs) will be routed to a NGL tank for storage until transported via truck to market. The low Btu/residue gas will be used as fuel for the heater treaters (when fired), compressor engine, and to maintain the pilot light on the flares. The remaining gas will be routed through the compressor to a gathering line for distribution and sale by South Alabama Gas District. The produced condensate and saltwater stored in the respective tanks at both well sites will remain onsite until trucked offsite.

Once the gas from the proposed well is connected to the ATIC 34-12 Well, the flares at both wells will serve as only emergency flares. Gas to the pilot for the flare is expected to be the only continuous stream routed to each flare. The emergency flares will be used intermittently for emergencies, for compressor blowdowns, for facility maintenance, for equipment repairs and for gas plant and/or well shutdowns.

EMISSIONS

Prior to the Modification

Table 1 shows the potential uncontrolled, controlled, and expected emissions from emissions sources located at the existing 34-12 Well and the Barnett Plant prior to this modification. For the potential uncontrolled emissions, the full well stream of gas produced at the well (via the separator and tank gases (including flash, working and breathing)) are vented to atmosphere 8,760 hours per year, the engine located at the Barnett Plant is uncontrolled, and no flaring occurs. For potential controlled emissions, all gas from the tanks is captured via the vapor recovery unit (VRU) and closed vent system and flared at the ATIC 34-12 Well 8,760 hours per year and the compressor engine is equipped with a NSCR/3-way catalyst to reduce emissions from the combined sites. The NSCR/3-way catalyst will reduce NO_X emissions by 93.7% and CO emissions by 81%. 40 CFR 60 Subpart OOOOb restricts flaring; therefore, this method of operation is not expected, except where allowed.

For the expected emissions, the only continuous gas flared should be the pilot gas and only a small volume of gas is expected to be flared during periods of compressor blowdowns, facility maintenance, equipment repairs for gas and/or well shutdowns. In addition, all produced gas collected via the closed vent system is treated, processed, and routed to the sale pipeline and the engine is equipped with an NSCR. To maintain emissions from the facility below the requested synthetic minor operating permit limit of 99 tons per year of criteria pollutants and the limit for hazardous air pollutants of 9.9 TPY or less for a single HAPs or 24.9 TPY for a combination of HAPs, Pruet is expected to operate the combined sites by processing and treating all the gas and limiting flaring.

Total Facility-wide Emissions for the ATIC 31-12/Barnett Plant (TPY)				
	Pollutant	**Potential *Uncontrolled* Emissions**	**Potential *Controlled* Emissions**	***Expected* Emissions**
Criteria Pollutant Emissions (TPY)	**$PM_{2.5}$|PM_{10}**	**0.6**	**0.62**	**0.18**
	PM	**0.154**	**0.154**	**0.05**
	SO_2	**0.315**	**0.32**	**0.00**
	NO_X	**44.69**	**15.92**	**2.25**
	CO	**95.03**	**78.91**	**4.55**
	VOC	**4,909.07**	**57.63**	**0.85**
	Total HAPs	**140.97**	**2.24**	**0.54**
GHG Emissions (TPY)	**CO_2**	**26,344.42**	**26,631.99**	**1,346.75**
	N_2O	**0.047**	**0.05**	**0.00**
	CH_4	**4,832.93**	**99.99**	**1.41**
	Mass Sum	**31,177.39**	**26,732.02**	**1,348.17**
	CO_{2e}	**147,181.48**	**29,159.78**	**1,382.80**

Table 1: Facility-wide ATIC 34-12 Well/Barnett Emissions Prior to this Modification

Except where provided by the manufacturer for the engine, all criteria pollutant emissions were determined using AP-42 emission factors, greenhouse gas (GHG) emissions factors found in Table C-1 and C-2 Part 98 Subpart C, and the fuel gas analysis submitted with the application. The majority of uncontrolled emissions from the ATIC 34-12/Barnett Plant were based on flash gas volatile organic compound (VOC) emissions from

the 500-barrel, power oil tank. The Vasquez-Beggs equation was used to determine emissions from this tank. EPA's Tank 4.0d software was used to determine working and breathing loss emissions from each of the storage vessels. Engine emissions were calculated based on manufacturer's emission factors and AP-42 emission factors for criteria pollutants and GHG emission factors found in found in Table C-1 and C-2 Part 98 Subpart C. Engine emission have been updated since the addition of the gas plant.

After the Modification

The proposed ATIC 33-8 Well is being added to the existing ATIC 34-12/Barnett Plant site. Table 2 shows the potential uncontrolled emission from the proposed ATIC 33-8 Well alone. These emissions are based on all gas (including separator and tank gases) from this well continuously vented to atmosphere 8,760 hours per year.

Total Facility-wide Potential Uncontrolled Emissions (TPY)					
	Pollutant	**Heater**	**Separator**	**Tanks**	**Total Emissions**
Criteria Pollutant Emissions (TPY)	**$PM_{2.5}$|PM_{10}**	0.016	0.485	0.036	**0.54**
	PM	0.004	0.10	0.01	**0.11**
	SO_2	0.001	0.387	0.028	**0.417**
	NO_X	0.215	14.082	2.034	**16.33**
	CO	0.180	76.621	11.069	**87.87**
	VOC	0.012	2,250.324	980.826	**3,231.16**
	Total HAPs	0.004	97.291	65.665	**162.96**
GHG Emissions (TPY)	**CO_2**	255.984	26,292.767	4,084.273	**30,633.03**
	N_2O	0.000	0.046	0.007	**0.053**
	CH_4	0.005	5,755.808	178.173	**5,933.99**
	Mass Sum	255.990	32,048.621	4,180.825	**36,485.44**
	CO_{2e}	256.248	187,467.484	8,458.940	**196,182.67**

Table 2: ATIC 33-8 Well Uncontrolled Emissions

Table 3 demonstrates the potential controlled emissions for the ATIC 33-8 Well. All gas from the tanks is captured via the VRU and CVS and flared onsite at the well 8,760 hours per year. As mentioned previously, NSPS OOOOb restricts flaring; therefore, this method of operation is not expected, except where allowed. However, Pruet will be required to flare the produced gas temporarily until the construction of the gathering line that will route the gas from the ATIC 33-8 Well to the inlet separator of the ATIC 34-12 Well where the gas will be comingled together. According to Pruet, it will take approximately three months to purchase the right of way and construct the gathering line.

Total Facility-wide Potential Controlled Emissions (TPY)				
	Pollutant	**Heater**	**Flare**	**Total Emissions**
Criteria Pollutant Emissions (TPY)	**$PM_{2.5}$|PM_{10}**	0.016	0.00	**0.016**
	PM	0.004	0.00	**0.004**
	SO_2	0.00	0.42	**0.42**
	NO_X	0.21	16.06	**16.27**
	CO	0.18	87.38	**87.56**
	VOC	0.012	64.43	**64.44**
	Total HAPs	0.004	2.09	**2.09**
GHG Emissions (TPY)	**CO_2**	255.98	29,660.01	**29,915.99**
	N_2O	0.00048	0.05	**0.053**
	CH_4	0.005	118.68	**118.68**
	Mass Sum	255.99	29,778.74	**30,034.73**
	CO_{2e}	256.25	32,642.50	**32,898.75**

Table 3: ATIC 33-8 Well Controlled Emissions

Table 4 demonstrates the expected emissions from the ATIC 33-8 Well. The expected emissions are emissions after the gather line is installed and the only gas routed to the flare continuously is for the pilot. The proposed flare will be designated as an emergency flare that will be used intermittently for emergencies, for facility maintenance, for equipment repairs and for gas plant and/or well shutdowns. All gas from the proposed ATIC 33-8 Well will be collected via the closed vent system and routed through the gathering line to the ATIC 34-12 Well. The gas from this well would not be burned in the well flare unless necessary and as allowed by NSPS OOOOb. Pruet has previously agreed to shut in the wells if the gas cannot be treated and processed and routed to the sales pipeline.

Total Facility-wide Expected Emissions (TPY)				
	Pollutant	**Heater**	**Flare Pilot**	**Total Emissions**
Criteria Pollutant Emissions (TPY)	**$PM_{2.5}$|PM_{10}**	0.016	0.011	**0.027**
	PM	0.005	0.014	**0.019**
	SO_2	0.001	0.010	**0.011**
	NO_X	0.215	0.426	**0.64**
	CO	0.180	2.317	**2.50**
	VOC	0.012	1.326	**1.34**
	Total HAPs	0.004	0.349	**0.35**
GHG Emissions (TPY)	**CO_2**	255.984	759.781	**1,015.77**
	N_2O	0.000	0.001	**0.002**
	CH_4	0.005	3.395	**3.40**
	Mass Sum	255.990	763.177	**1,019.17**
	CO_{2e}	256.248	855.195	**1,111.44**

Table 4: ATIC 33-8 Well Expected Emissions

Table 5 represents the facility-wide emissions from the Barnett Area No. 1 (including the ATIC 34-12, ATIC 33-8, and Barnett Plant) after this modification. Uncontrolled emissions would be based on venting all gas from both wells to atmosphere and not equipping the engine with a control device. Controlled emissions would be based on produced gas from each well combusted in the well flares and the engine equipped with a control device. Expected emissions represent the emissions from Barnett Area No. 1 after the gathering line for the ATIC 33-8 Well is constructed and the gas is collected, treated, and processed.

Total Facility-wide Emissions for the Barnett Area No. 1 (TPY)				
	Pollutant	**Potential *Uncontrolled* Emissions**	**Potential *Controlled* Emissions**	***Expected* Emissions**
Criteria Pollutant Emissions (TPY)	**P $M_{2.5}$|PM_{10}**	**1.15**	**0.63**	**0.21**
	PM	**0.27**	**0.16**	**0.077**
	SO_2	**0.74**	**0.74**	**0.011**
	NO_X	**61.02**	**32.18**	**3.18**
	CO	**182.89**	**166.47**	**8.66**
	VOC	**8,140.23**	**122.07**	**2.57**
	Total HAPs	**303.93**	**4.33**	**1.13**
GHG Emissions (TPY)	**CO_2**	**56,977.43**	**56,547.97**	**2,882.05**
	N_2O	**0.10**	**0.093**	**0.003**
	CH_4	**10,766.92**	**218.66**	**7.06**
	Mass Sum	**67,662.83**	**56,766.75**	**2,889.13**
	CO_{2e}	**343,364.15**	**62,058.53**	**3,095.37**

Table 5 : Facility Wide Emissions for the Proposed Barnett Area No. 1 Facility After this Modification

The emission factors used to calculate emissions for the original project will be used to calculate emissions for this project.

REGULATIONS

The following regulations may be applicable to Barnett Area No. 1 Facility:

ADEM Admin. Code r. 335-3-4-.01(1) (a and b), "Visible Emissions"

ADEM Admin. Code r. 335-3-4-.01(1)(a) states that except for one six-minute period in any sixty-minute period, no person shall emit particulate emissions to the atmosphere of an opacity of greater than twenty percent (20%) as determined by a six (6) minute average.

ADEM Admin. Code r. 335-3-4-.01(1)(b) states that a person may discharge into the atmosphere from any source of emissions, particulate of an opacity not greater than that designated as forty percent (40%) opacity as determined by a six (6) minute average.

ADEM Admin. Code r. 335-3-4-.01(2) states that if visible emissions are observed, opacity should be determined using Method 9 of 40 CFR Part 60, Appendix A-4. Method 9 must be completed by a person certified to conduct it.

Each heater treater (when fired with gas) and the engine will be subject to these regulations. The existing and proposed flare will comply with the requirements of this regulation by complying with the more stringent opacity standards and design requirements found in 40 CFR 60 Subpart OOOOb.

ADEM Admin. Code r. 335-3-4-.03(1) and (4) "Fuel Burning Equipment"

ADEM Admin. Code r. 335-3-4-.03(1) states that no person shall cause or permit the emission of particulate matter from fuel-burning equipment in a Class 2 County in excess of the amount shown in Table 4-1 for the heat input allocated to such source. Per ADEM Admin. r. 335-3-Appendix A, Conecuh County is a Class 2 County. **ADEM Admin. Code r. 335-3-4-.03(4)** states that new fuel-burning sources emitting particulate sources are subject to the rules and regulations for Class 1 Counties regardless of their location.

The heater treaters, when fired, will be subject to this rule. The allowable emission rate from Table 4-1 in ADEM Admin r. 335-3-4-.03 is 0.5 lbs/MMBtu. The heater treaters will comply with this rule by burning only natural gas as fuel.

ADEM Admin. Code r. 335-3-5-.01(1)(b), "Fuel Combustion"

ADEM Admin. Code r. 335-3-5-.01(1)(b) states that no person shall cause or permit the operation of a fuel burning installation in a Sulfur Dioxide Category II County in such a manner that sulfur oxides, measured as sulfur dioxide (SO_2), are emitted in excess of 4.0 pounds per million BTU heat input.

Per ADEM Admin. r. 335-3-Appendix B, Conecuh County is a Category II County. The heater treaters, when fired, will be subject to this rule and will comply with this rule by burning only natural gas as fuel.

ADEM Admin. Code r. 335-3-5-.03(1), "Petroleum Production"

ADEM Admin. Code r. 335-3-5-.03(1), applies to facilities that handle natural gas that contain more than 0.10 grain of hydrogen sulfide (H_2S) per standard cubic foot (SCF) (approximately 160 parts per million volume (ppmv). According to the May 7, 2025 gas analysis submitted in the application, the ATIC 33-8 Well is expected to contain 12 ppmv of H_2S; therefore, neither the proposed well, nor the existing well will be subject to this regulation.

ADEM Admin. Code r. 335-3-6, "Control of Organic Emissions"

This chapter is applicable to all sources of volatile organic compound (VOC) with the potential VOC emission rate of 100 tons per year (TPY) or greater [ADEM Admin. Rule 335-3-6-.01]. The uncontrolled potential VOC emissions from this project would be greater than 100 TPY (see Table 2 in the Emissions section). Only the potential applicable sections under Chapter 6 for the proposed project will be discussed.

ADEM Admin. Code r. 335-3-6-.03 covers loading and storage of VOC and applies to liquids with a VOC true vapor pressure (TVP) greater than or equal to 1.5 psia under storage conditions. The 21,000-gallon condensate storage vessels would be subject to this regulation because it meets the TVP requirement and it would have potential emissions greater than 100 TPY. Since that condensate storage vessel will also be subject to requirements under 40 CFR 60 Subpart OOOOb [NSPS OOOOb], it will comply with that subpart to satisfy this regulation. The remaining condensate storage vessels would not be subject to this subpart. The saltwater tank would not be subject to this rule because it would not meet the vapor pressure requirements and it does not have the potential for VOC emissions greater than 100 TPY.

ADEM Admin. Code r. 335-3-6-.04 covers fixed-roof petroleum liquid storage vessels with a design capacity greater than 150,000 liters (40,000 gallons) containing petroleum liquid whose true vapor pressure (TVP) is greater than 10.5 kilo Pascals (1.52 psia). None of the proposed storage vessels at the ATIC 33-8 Well nor the

existing storage vessels at the ATIC 34-12 Well would meet the design capacity requirements under this subpart. Also, this rule would not apply to storage vessels at the facility because the capacity of the storage vessels will be less than 423,000 gallons and the produced oil and/or condensate will be stored prior to lease custody transfer [ADEM Admin. Rule No. 335-3-6-.04(2) and (3)(b)]. Therefore, this rule would not apply.

ADEM Admin. Code r. 335-3-10| 40 CFR Part 60, "Standards of Performance for New Stationary Sources [NSPS]"

This chapter covers standards under 40 CFR 60 and its Appendices as designated in Alabama Administrative Code rules 335-3-10-.02 and -.03 incorporated by reference as they exist in 40 CFR 60 (July 1, 2024), and 89 FR 70505 [8/30/2024; amendments to Subparts IIII and JJJJ], and 89 FR 83296 [10/15/2024; amendments to Subparts A, and K_b and addition of Subpart Kc], as amended by the word or phrase substitutions given in Alabama Administrative Code r. 335-3-10-.04. The emission standards in this chapter supersede the emissions standards in Chapters 335-3-3, -4, -5, -6, -7, and -8 provided that both the criteria in ADEM Admin. Code r. 335-3-10-.01(2) are met: a source category is subject to the regulations in this Chapter for a specific pollutant to which an emission standard under this chapter applies and the emission standard under Chapters 335-3-3, -4, -5, -6, -7, and -8 is more stringent that the emission standards in this chapter for the specific pollutant regulated.

ADEM Admin. Code r. 335-3-10-.02(1) | 40 CFR 60 Subpart A, "General Provisions"

The requirements under this subpart are subject by reference in an applicable subpart. 40 CFR §60.5425b and Table 5 under 40 CFR 60 Subpart OOOOb indicate the applicable requirements under this subpart for the compressor, fugitive components, and storage vessels. Table 3 under 40 CFR 60 Subpart JJJJ indicates the applicable requirements under this subpart for the existing engine.

ADEM Admin. Code r. 335-3-10-.02(9)(c) | 40 CFR Part 60 Subpart Kc, "Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) **[NSPS Kc]**

This subpart was adopted by the Department, effective October 13, 2025. The requirements under this subpart may be applicable to the proposed storage vessels. This subpart applies to each storage vessel with a capacity greater than or equal to 20,000 gallons (75.7 m^3) that is used to store volatile organic liquid (VOL) for which construction, reconstruction, or modification commenced after October 4, 2023 [40 CFR §60.110c(a)]. The proposed 500-barrel (21,000 gallon) power oil storage tank would have a design capacity greater than 20,000 gallons; therefore, it would be subject to this subpart based on the design capacity. However, vessels with a design capacity less than or equal to 420,000 gallons used for petroleum or condensate stored, processed or treated prior to custody transfer are not subject to this subpart [40 CFR §60.110c(b)(4)]. Therefore, none of the proposed tanks would be subject to this subpart.

ADEM Admin. Code r. 335-3-10-.02(88) | 40 CFR 60 Subpart JJJJ, "Standards of Performance for Stationary Spark Ignition Internal Combustion Engines" **[SI RICE, NSPS JJJJ]**

No new engines are being proposed with this project. However, the existing engine located at the Barnett Plant would remain subject to the requirements of this subpart.

40 CFR 60 Subpart OOOOb, "Standards of Performance for Crude Oil and Natural Gas Facilities" [NSPS OOOOb] for which construction, reconstruction, or modification occurred after December 6, 2022. This subpart has not been adopted by the Department. Additional requirements under this subpart will be added to the permit as a result of this project.

This subpart established emission standards and compliance schedules for the control of greenhouse gases (GHG) through the limitation of methane (CH_3) and for the control of VOC and SO_2 emissions for affected facilities in the crude oil and natural gas source category [40 CFR §60.5360b(a)]. Compliance with the requirements of this subpart shall be met upon initial startup of affected facilities, except as specified in the applicable sections of 40 CFR §60.5370b(a)(1) through (9) and 40 CFR 60.5377b(b) or (c) [40 CFR §60.5370b(a)].

At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions [40 CFR §60.5370b(b)].

- 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.
- The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided in 40 CFR §60.8(c) do not apply to this subpart.

Alternative means of emission limitations for GHG and VOC emissions from well completions, liquids unloading operations, process equipment, and fugitive emissions components may be elected as specified in 40 CFR §60.5399b.

Initial compliance with the standards for each applicable affected facility shall be met as specified in 40 CFR §60.5410b. Except as otherwise provided, the initial compliance period begins on the date specified in 40 CFR §60.5370b and ends no later than 1 year after that date. The initial compliance period may be less than one full year [40 CFR §60.5410b]. The additional requirements specified in 40 CFR §60.5411b must be met to determine initial compliance for covers and closed vent systems. The additional requirements specified in 40 CFR §60.5412b must be met to determine initial compliance for control devices. Pruet initially demonstrated compliance with NSPS OOOOb for fugitive components by submitting the report to EPA on May 15, 2026, and conducted initial testing on the compressor engine (ENG-01) to demonstrate compliance with NSPS JJJJJ on February 3, 2026.

An annual report, where applicable, must be submitted via the Compliance and Emission Data Reporting Interface (CEDRI) website according to the requirements in 40 CFR §60.5420b(b)(15) for all affected facilities

- The initial annual report is due no later than ninety (90) days after the end of the initial compliance period as determined according to 40 CFR §60.5410b.
- Subsequent annual reports are due no later than the same date each year as the initial annual report.

Records specified in 40 CFR §60.7(f) and specified in 40 CFR §60.5420b(c) for applicable affected facilities must be maintained either onsite or at the nearest local field office for at least 5 years. Electronic reporting is required for notifications and reports according to 40 CFR §60.5420b(d). Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation [40 CFR §60.5420b(c)].

Super-Emitter Events

The requirements in 40 CFR §60.5371b will apply for super-emitter events after January 22, 2027. A super emitter event is as follows:

- Defined as any emissions event that is located at or near an oil and natural gas facility (individual well site, centralized production facility, natural gas processing plant, or compressor station)
- Detected using remote detection methods
- Has a quantified emissions rate of 100 kilogram per hour (kg/hr) of methane or greater

The qualifications specified in 40 CFR §60.5371b(a) shall be met for third-party notifiers. The certifications for third party notifiers shall be met as specified in 40 CFR §60.5371b(b). Notifications of super-emitter events shall be submitted to EPA within 15 calendar days of the date of detection of the super-emitter event and according to 40 CFR §60.5371b(c). Within five (5) calendar days of receiving a notification form EPA of a super-emitter event, the facility must initiate a super-emitter event investigation according to 40 CFR §60.5371b(d). The facility must submit the results of the super-emitter event investigation to EPA within 15 days of receiving notification from EPA according to the requirements in 40 CFR §60.5371b(e).

Well Affected Facility Requirements

APPLICABILITY

The proposed 33-8 Well is being drilled for the purpose of producing oil or natural gas located within the Crude Oil and Natural Gas source category; therefore, it is an affected facility [40 CFR §60.5365b(a), 40 CFR §60.5430b]. The location of the proposed well within 1 mile of the existing sites will result in the creation of a second well affected facility rather than a centralized production facility (CPF). The proposed 33-8 Well will be equipped with its own storage vessels and the oil, condensate, produced water and intermediate liquids from this well will not be routed to the existing 34-12 Well for the purpose of sale or processing to sell, therefore, the Barnett Area No. 1 will not be classified as a CPF. In addition, the existing Barnett Plant is not a natural gas processing plant by definition in 40 CFR §60.5430b. A Joule-Thompson (JT) Unit is used to recover natural gas liquids (NGLs) from the produced gas. This unit does not meet the definition of a natural gas processing plant (gas plant); therefore, it would not be an affected facility under this subpart. Also, the existing SulfaTreat Unit at the Barnett Plant would not be subject to the requirements of a sweetening unit under this subpart.

The requirements for an affected well facility would apply to both the existing ATIC 34-12 Well and the proposed ATIC 33-8 Well.

WELL COMPLETIONS AT WELL AFFECTED FACILITY

In addition to 40 CFR §60.14, a modification at an existing well occurs if it is hydraulically fractured or hydraulically refractured [40 CFR §60.5365b(a)(1)(i) or (ii)]. Except as provided in 40 CFR §60.5365b(e)(3)(ii)(C) and (i)(3)(ii), any action described by 40 CFR §60.5365b (a)(1)(i) and (ii), by itself, does not affect the modification status of process unit equipment, centrifugal or reciprocating compressors, pumps, or process controllers. The existing 34-12 Well is not being hydraulically fractured or refractured for this project; therefore, a modification under 40 CFR §60.5365b(a)(1) will not occur. As result the requirements for the 34-12 Well will be unchanged. Since the proposed 33-8 Well is a new single well drilled to produce oil or natural gas, it will become a well affected facility subject to this subpart [40 CFR §60.5365b (a)].

If well completion with hydraulic fracturing or refracturing was to occur at either wellsite, the requirements in 40 CFR §60.5375b must be met.

LIQUID UNLOADING OPERATIONS AT WELL AFFECTED FACILITY

For an affected well facility, there are requirements and standards under 40 CFR §60.5376b for liquids unloading operations depending on if loading operations results in venting of methane and VOC emissions to the atmosphere [40 CFR §60.5376b]. Liquid unloading, the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production, is not expected to occur at either well; however, if it occurs, the requirements specified in 40 CFR §60.5376b must be met.

For the purposes of a well affected facility, a liquids unloading event is not considered to be a modification [40 CFR §60.5365b(a)(2)].

ASSOCIATED GAS WELLS AT WELL AFFECTED FACILITY

Associated gas is natural gas from wells operated primarily for oil production that is released from the liquid hydrocarbon during the initial stage of separation after the wellhead. Gas from wildcat or delineation wells is not associated gas.

Originally Ventex (now Pruet) requested to comply with 40 CFR §60.5377b(a) by complying with the requirements specified in 40 CFR §60.5377b(f)(1) [40 CFR §60.5377b(b)]. 40 CFR §60.5377b(f)(1) required the facility to temporarily route the associated gas to a control device that reduces methane and VOC emissions by at least 95.0 percent continually upon startup. The associated gas had to be routed through a closed vent system that meets the requirements of 40 CFR §60.5411b(a) and (c) and the control device had to meet the conditions specified in 40 CFR §60.5412b. The facility elected to route the vapors from the separator and tanks through a closed vent system to the flare for combustion. The facility provided a detailed analysis to the Department, dated March 21, 2025, documenting and certifying the technical reasons for this infeasibility to comply with 40 CFR §60.5377b(a) [40 CFR §60.5377b(a), (f), (f)(1), (g)].

The 34-12 Well was constructed between May 7, 2024, and May 7, 2026. Since it is after May 7, 2026, and the 34-12 Well will not undergo a modification under this project, complying with 40 CFR §60.5377b(f)(1) is no longer an option to comply with 40 CFR §60.5377b(a) for the existing well. The facility is now required to comply with one of the options in 40 CFR §60.5377b(a) at all times. The facility has elected to recover associated gas from the separator at the ATIC 34-12 Well and route it to a gas gathering flow line or collection system to a sales line. Also, some of the gas for the 34-12 Well is being used as onsite fuel for the compressor engine and as fuel gas for the flare pilot, therefore, the facility is in continuous compliance with 40 CFR §60.5377b(a) [40 CFR §60.5377b(a)(1) and (a)(2)].

Since the construction of the proposed 33-8 Well will be after May 7, 2026, and the well is a separate well affected facility, the facility must comply with 40 CFR §60.5377b(a) upon startup and at all times. The facility will not be able to begin producing the 33-8 Well until after the gathering line to route the gas from the 33-8 Well to the 34-14 well is constructed. Continuous flaring will no longer be allowed at a wellsite.

EMISSION STANDARDS

Once the gathering line is complete, the gas from the 33-8 Well will be collected via the VRU and routed to the 34-12 Well where it will be comingled with the 34-12 Well gas. The combined gas will then be routed to the Barnett Plant where it will be processed, treated, and sent primarily to the South Alabama Gas District distribution system for sales. Gas that is not sold will be used for fuel in the heater treater (if fired), as fuel for the engine, or as pilot fuel gas for the flares. The produced condensate from the 33-8 Well will be stored on the wellsite until transferred offsite by truck. These actions will demonstrate continuous compliance with 40 CFR §60.5377b(a)(1) and (a)(2).

Temporary Flaring

This section of the regulation has been revised as of April 9, 2026, which was after the initial issuance of permits for the 34-12 Well. Revisions will be included in the permit.

The facility will be allowed to temporarily route the associated gas to a flare or other control device that achieves a 95.0 percent reduction in VOC and methane emissions in the following situations and for the durations specified below [40 CFR §60.5377b(d)(1)-(4)]. The associated gas must be routed through a closed vent system that meets the requirements of 40 CFR §60.5411b(a) and (c) and the control device must meet the conditions specified in 40 CFR § 60.5412b during the period when the associated gas is routed to the flare.

- During a malfunction or incident that endangers the safety of operator personnel or the public the facility is allowed to route associated gas to a flare or control device until the malfunction or incident is resolved, but not longer than 72 hours per incident. Temporarily routing associated gas to a flare or control device is allowed only until the malfunction or incident is resolved. Notwithstanding the previous sentences, if there are exigent circumstances that reasonably require routing to a flare or control device for more than 72 hours, 40 CFR §60.5377b(d)(1)(i) through (iii) applies [40 CFR §60.5377b(d)(1)].
- During repair and maintenance, including blow downs, a production test, or commissioning, the facility is allowed to route associated gas to a flare or control device until the incident is resolved, but no longer than 72 hours per incident. Temporarily routing associated gas to a flare or control device is allowed only until the incident is resolved. Notwithstanding the previous sentences, if there are exigent circumstances that reasonably require routing to a flare or control device for more than 72 hours, 40 CFR §60.5377b (d)(1)(i) through (iii) apply [40 CFR §60.5377b(d)(2)].
- When the facility is unable to send the gas to distribution systems sales line due to a temporary interruption in service from the gathering or pipeline system, the facility is allowed to route the associated gas to a flare or route to a control device for the duration of the temporary interruption not to exceed 30 days per incident [40 CFR §60.5377b(a)(1), (d)(3)].
- During periods when the composition of the associated gas does not meet pipeline specifications, or when the composition of the associated gas does not meet the quality requirements for use as a fuel for in the heater treater, engine, or pilot light, the facility is allowed to route to a flare or control device until the associated gas meets the required specifications or for 72 hours per incident, whichever is less [40 CFR §60.5377b(a)(1), (d)(4)].

Records must be kept of all instances in which associated gas is temporarily routed to a flare or to a control device in accordance with 40 CFR §60.5420b(c)(3)(i)(B) and reported in the annual report in accordance with 40 CFR §60.5420b(b)(4)(i)(B) [40 CFR §60.5377b(d), 40 CFR § 60.5420b(b) & (c)].

Temporary Venting

If the facility is complying with 40 CFR §60.5377b(a) or (d), the associated gas may be vented in the situations and for the durations identified in 40 CFR §60.5377b(e)(1), (2) or (3) per incident [40 CFR §60.5377b(e)]. The cumulative period of venting must not exceed 24 hours for any calendar year [40 CFR §60.5377b(e)].

- For up to 12 hours per incident to protect the safety of personnel.
- For up to 30 minutes per incident during bradenhead monitoring.
- For up to 30 minutes per incident during a packer leakage test.

Records must be kept of all venting instances in accordance with 40 CFR §60.5420b(c)(3)(ii) and reported in the annual report in accordance with 40 CFR §60.5420b(b)(4)(ii).

EMISSIONS MONITORING

Initial compliance with the standards that apply to associated gas wells as required by 40 CFR § 60.5410b(c) must be demonstrated [40 CFR §60.5377b(h), 40 CFR §60.5410b(c)].

Continuous compliance with the standards that apply to associated gas wells as required by 40 CFR §60.5415b(c) must be demonstrated [40 CFR §60.5377b(i)]. Additional continuous compliance requirements for associated gas well must be met as specified in 40 CFR § 60.5415b(f).

RECORDKEEPING AND REPORTING REQUIREMENTS

The notification requirements specified in 40 CFR §60.5420b(a) shall be met where applicable.

The reporting requirements specified in 40 CFR §60.5420b(b)(1) and (4), and (b)(11) and (12), as applicable must be met [40 CFR §60.5377b(j), 40 CFR § 60.5420b(b)]. If a well affected facility undergoes a change of ownership during the reporting period, the reporting requirements under 40 CFR §60.5420b(b)(2)-(4) must be met.

The recordkeeping requirements specified in 40 CFR §60.5420b(c)(3) and (8), and (c)(10) through (13), as applicable must be maintained for well affected facilities [40 CFR §60.5377b(j), 40 CFR §60.5420b(c)].

CONTROL DEVICE REQUIREMENTS

Controls for Associated Gas Wells

Emission Standard

Associated gas wells at well affected facilities are allowed to temporarily route associated gas to either a flare or control device that achieves a 95.0 percent reduction in VOC and methane emissions in the situations and for the durations identified in 40 CFR §60.5377b(d). The associated gas must be routed through a closed vent system that meets the requirements of 40 CFR §60.5411b(a) and (c) and the flare, when used, must meet the conditions specified in 40 CFR §60.5412b during the period when the associated gas is routed to the flare [40 CFR §60.5377b(d), 40 CFR 60.5411b(a), (c), 40 CFR §60.5412b]. A flare used to comply with 40 CFR §60.5412b(a), must be designed and operated according to 40 CFR §60.5412b(a)(3)(i) through (viii) as follows [40 CFR §60.5412b(a)(3), (d)]:

- The flare shall meet the applicable assist requirements found in 40 CFR §60.5412b(a)(3)(i)-(v)
- The flare shall be operated at or above the minimum inlet gas flow rate established based on manufacturer recommendations [40 CFR §60.5412b(a)(3)(vi)]
- The flare shall be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. The compliance determination with the visible emission limits using Method 22 of appendix A-7 to this part must be conducted, or the flare must be monitored according to 40 CFR § 60.5417b(h) [40 CFR §60.5412b(a)(3)(vii)]
- After January 22, 2027, the facility must install and operate a continuous burning pilot or combustion flame. After January 22, 2027, an alert must be sent to the nearest control room whenever the pilot or combustion flame is unlit [40 CFR §60.5412b(a)(3)(viii)]

Alternative, to demonstrate that a flare or enclosed combustion device reduces methane and VOC in the gases vented to the device by 95.0 percent by weight or greater, as outlined in 40 CFR §60.8(b), a request

following the requirements outlined in 40 CFR §60.5412b(d)(1)-(5) for an alternative test method may be submitted [40 CFR §60.5412b(d)].

Each control device installed at the well storage vessels, or process unit equipment affected facilities must be operated in accordance with the requirements specified in 40 CFR §60.5412b(b)(1) and (2). Each control device used to comply with NSPS OOOOb must be operated at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. More than one affected facility maybe be vented to a control device subject to this subpart.

EMISSION MONITORING

The flare will be monitored in accordance with the requirements of 40 CFR §60.5417b(h); therefore, continuous compliance must be demonstrated according to the applicable requirements of 40 CFR §60.5415b(f).

PERFORMANCE TESTING

The facility is exempt from the requirements to conduct initial and periodic performance tests and design analyses for a flare designed and operated according to 40 CFR §60.5412b(a)(3) [40 CFR §60.5413b]. However, the facility must conduct a compliance determination using 40 CFR 60 Method 22 of appendix A- to determine visible emissions or monitor the flare according to 40 CFR §60.5417b(h). The net heating value of the vent gas must be determined according to 40 CFR §60.5417b(d)(8)(ii) [40 CFR §60.5413b(a)(1)].

RECORDKEEPING AND REPORTING

If the flare is using an alternative test method approved under 40 CFR §60.5412b(d), comply with 40 CFR §60.5417b(i). The facility must submit annual reports for control devices as required in 40 CFR §60.5420b(b)(1) and (11) and must maintain records as specified in 40 CFR §60.5420b(c)(11) [40 CFR §60.5417b(i), (j)].

COMPRESSOR REQUIREMENTS

Reciprocating Compressor

Each reciprocating compressor, which is a single reciprocating compressor, is an affected facility under this subpart [40 CFR §60.5365b(c)]. There are no new reciprocating compressors being added for this project. The status of the existing reciprocating compressor is not considered an affected facility and would not change since the site will not be designated as a centralized production facility.

PROCESS CONTROLLER REQUIREMENTS

The requirements for natural gas driven process controllers are covered as an affected facility under 40 CFR §60.5365b(d). If the facility proposes the installation of natural gas-driven process controllers at this facility, they would be subject to the requirements of this subpart. Natural gas-driven process controllers that function as emergency shutdown devices and process controllers that are not driven by natural gas are not included in the affected facility. Pruet did not specify the use of natural gas process controllers in this permit application.

A non-natural gas-driven process controller is an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

SWEETENING UNIT REQUIREMENTS

The SulfurTreat Tower was installed at the Barnett Plant during the last project proposed for this facility. Since the SulfurTreat unit does not meet the definition of a sweetening unit, the requirements under 40 CFR §60.5405b through 40 CFR §60.5407b, 40 CFR §60.5410b(i), 40 CFR §60.5415b(k), and 40 CFR §60.5423b do not apply [40 CFR §60.5365b(g)(4)]. The use of an additional sweetening unit is not being proposed for this project.

STORAGE VESSEL REQUIREMENTS

The proposed 33-8 Well will be equipped with storage vessels that will be used to store condensate and water produced only at that well site. Because this project will occur prior to January 22, 2027, and none of the produced condensate or water from the proposed well will be routed to the ATIC 34-12 storage vessels a modification to the existing site will not be triggered [40 CFR §60.5365b(e)(3)(ii)(C)]. The storage vessels at the 33-8 Well will be a separate tank battery and the facility must demonstrate compliance with the requirement for storage vessels specified in 40 CFR §60.5395b(a)(1) within 30 days after startup of production, if the requirements in 40 CFR §60.5365b(e)(5)(i) and (ii) are not met [40 CFR §60.5370b].

APPLICABILITY

Each storage vessel (or tank battery) that has the potential for VOC emissions equal to or greater than six (6) tons per year (TPY) or the potential for methane (CH_3) emissions equal to or greater than 20 TPY as determined by 40 CFR §60.5365b(e)(2) is an affected facility under this subpart [40 CFR §60.5365b(e)(1)(i) and (ii)]. The proposed storage vessels to be located at the facility and the maximum total vapor pressure (TVP) for the liquids stored in the storage vessels are found in Table 6 below. The tank battery for the proposed 33-8 Well has the potential to emit greater than 6 TPY of VOC and it has the potential to emit greater than 20 TPY of methane gas (see tank emissions in Table 2); therefore, the tank battery will be considered an affected facility under this subpart.

SOURCE ID	WELL LOCATION	TANKS CAPACITY GALLONS (BARRELS)	ROOF TYPE	LIQUID STORED	MAX TVP (PSIA)
T-07	33-8	21,000 (500)	Vertical Fixed	Crude Oil	4.5
T-08	33-8	16,800 (400)	Vertical Fixed	Crude Oil	4.5
T-09	33-8	16,800 (400)	Vertical Fixed	Crude Oil	4.5
T-10	33-8	16,800 (400)	Vertical Fixed	Crude Oil	4.5
T-11	33-8	16,800 (400)	Vertical Fixed	Crude Oil	4.5
T-12	33-8	16,800 (400)	Vertical Fixed	Salt Water	0.35

Table 6: Proposed 33-8 Well Storage Vessels

Uncontrolled potential tank VOC emissions from working loss, breathing loss, and flash emissions are found below in Table 7. These emissions are based on the facility releasing all the produced gas from the separator and storage vessels to atmosphere. Only the T-07 power oil tank would have the potential for flash loss due to it being open to atmosphere when uncontrolled.

UNCONTROLLED VOC EMISSIONS FROM PROPOSED 33-8 TANKS (TPY)				
SOURCE ID	**WORKING LOSS**	**BREATHING LOSS**	**FLASH EMISSIONS**	**TOTAL EMISSIONS**
T-07	3.874	0.45	968.50	**972.82**
T-08	1.59	0.42	-	**2.01**
T-09	1.59	0.42	-	**2.01**
T-10	1.59	0.42	-	**2.01**
T-11	1.59	0.42	-	**2.01**
T-12	-	-	-	-
Total Emissions	**10.23**	**2.13**	**968.50**	**980.86**

Table 7: Uncontrolled VOC Tank Emissions from the 33-8 Well

Tank emissions (working, breathing, and flash) from the 33-8 Well are expected to be collected via a vapor recovery unit, routed to the 34-12 Well where the streams will be combined, and then routed to the Barnett Plant for processing. Since the gas will be recovered, there will not be any emissions from the tanks unless temporary flaring occurs when allowed by NSPS OOOOb. The proposed flare will be designed to have a destruction efficiency of 98%. A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 TPY shall remain an affected facility under this subpart [40 CFR §60.5365b(e)(4)]. The tank battery at the proposed 33-8 wellsite will be an affected facility under this subpart.

EMISSION STANDARDS

The potential for VOC and methane emissions must be calculated as the cumulative emission from all storage vessels within the tank battery as specified by the applicable requirements in 40 CFR §60.5365b(e)(2)(ii) within thirty (30) day after startup of production, or within 30 days after reconstruction or modification [40 CFR §60.5365b(e)(2), (e)(2)(ii)]. Legally and practicably enforceable limits in an operating permit or other requirements established under a Federal, State, local or Tribal authority may be taken into account when determining emissions for affected storage vessels [40 CFR §60.5365b(e)(2)(i)]. The facility has not requested to take an enforceable limit on the storage vessels; however, any vapor from a storage vessel that is recovered and routed to a process through a vapor recovery unit (VRU) designed and operated as specified below is not required to be included in the determination of potential for VOC or methane emissions for purposes of determining affected facility status, provided that the following requirements are met [40 CFR §60.5365b(e)(5)]:

- Cover requirements specified in 40 CFR §60.5411b(b) [40 CFR §60.5365b(e)(5)(i), 40 CFR §60.5411b]
- Closed vent system requirements specified in 40 CFR §60.5411b(a)(2) through (4) and (c) [40 CFR §60.5365b(e)(5)(ii)]
- In the event of removal of apparatus that recovers and routes vapor to a process, or operation that inconsistent with the conditions under 40 CFR §60.5365b(e)(5)(i) and (ii), the facility must determine the storage vessels potential for VOC emissions according to 40 CFR §60.5395b(e)(2) within 30 days of such removal or operation [40 CFR §60.5365b(e)(5)(iv)].

Gas from the proposed 33-8 Well will be routed to a process via a VRU; therefore, compliance with 40 CFR §60.5395b will only be required if the conditions in 40 CFR §60.5365b(e)(5) are not met.

The requirements of 40 CFR §60.5365b(e)(6) apply to each storage vessel affected facility immediately upon startup, startup of production, or return to service.

- A storage vessel affected facility or portion of a storage vessel affected facility that is reconnected to the original source of liquids remains a storage vessel affected facility subject to the same requirements that applied before being removed from service.
- Any storage vessel that is used to replace a storage vessel affected facility, or portion of a storage vessel affected facility, or used to expand a storage vessel affected facility assumes the affected facility status of the storage vessel affected facility being replaced or expanded.

EMISSION MONITORING

Initial and continuous compliance with requirements for closed vent systems (CVS), covers, and bypass devices shall be met by conducting inspections as specified in 40 CFR §60.5416b(a)(1)-(4). Beginning January 22, 2027, initial and periodic inspections for no identifiable emissions from covers and closed vent systems shall be conducted as specified in 40 CFR §60.5416b(b)(1)(i). Monitoring must be conducted at the same frequency as specified for fugitive emission components affect facility located at the same type of site as specified in 40 CFR §60.5397b(g). If alternative technology used to conduct inspection and monitoring the requirements in 40 CFR §60.5398b shall be met.

COMPLIANCE AND PERFORMANCE TESTING REQUIREMENTS

Initial and periodic inspections shall be conducted according to the test method and procedures specified in 40 CFR §60.5416b(b)(1)(i), (2), (3) and (4) [40 CFR §60.5416b(a)]. Repairs shall be made as specified in 40 CFR §60.5416b(b)(5). Delay of repair is allowed as specified in 40 CFR §60.5416b(b)(6). Parts of the CVS or cover may be designated as unsafe to inspect (UTM) if the requirements in 40 CFR §60.5416b(b)(7) are met. Parts of the CVS or cover may be designated as difficult to inspect (DTM) if the requirements in 40 CFR §60.5416b(b)(8) are met.

RECORDKEEPING AND REPORTING REQUIREMENTS

Records that document compliance with the cover and CVS requirements for the storage vessel must be maintained [40 CFR §60.5365b(e)(5)(iii)]. Records of all CVS, cover, and bypass inspection results shall be maintained as specified in 40 CFR §60.5420b(c)(8) through (10) [40 CFR §60.5416b(b)(9)]. The reports specified in 40 CFR §60.5420b(11) are required to be submitted for the CVS and covers [40 CFR §60.5416b(b)(9)].

The notification, reporting and recordkeeping requirements under 40 CFR 60.5424b must be met for alternative continuous inspection and monitoring requirements for covers and closed vent systems.

PUMP REQUIREMENTS

The requirements for natural gas driven pumps are covered under 40 CFR §60.5365b(h). However, there are no natural gas driven pumps that will be located at the proposed well.

FUGITIVE EMISSION COMPONENTS REQUIREMENTS AT A WELL SITE

APPLICABILITY

Each fugitive emissions component affected facility, is the collection of fugitive emissions components at a well site, centralized production facility, or a compressor station [40 CFR §60.5365b(i)]. As stated previously, this facility would not be defined as centralized production facility (CPF) after implementation of this project. The facility will remain a well affected facility under this subpart.

For purposes of 40 CFR § 60.5397b and 40 CFR § 60.5398b, a "modification" to a well site occurs as specified in 40 CFR § 60.5365b(i):

- A new well is drilled at an existing well site;
- A well at an existing well site is hydraulically fractured; or
- A well at an existing well site is hydraulically refractured.

For this project the ATIC 33-8 Well will be a new well at an existing well site.

EMISSION STANDARDS

Fugitive emissions components affected facilities must comply with the requirements in 40 CFR §60.5397b and as follows to reduce fugitive emissions of methane and VOC [40 CFR §60.5397b]:

- Comply with the general requirements specified in 40 CFR §60.5397b(a)
- The requirements of 40 CFR §60.5397b(a) through (l) are independent of the cover and closed vent system requirements in 40 CFR §60.5411b and they shall be met [40 CFR §60.5397b]
- The requirement in 40 CFR §60.5398b(a) may be elected as an alternative to GHG and VOC standards in 40 CFR §60.5397b.
- Meet the requirements for well closures in accordance with 40 CFR §60.5397b(l) [40 CFR §60.5397b(a), (l)].

EMISSION MONITORING

To demonstrate compliance with the monitoring requirements under this subpart, the following must be met [40 CFR §60.5397b(a)]:

- All fugitive emissions components must be monitored in accordance with 40 CFR §60.5397b(b) through (g).
- All sources of fugitive emissions must be repaired in accordance with 40 CFR §60.5397b(h).

COMPLIANCE AND PERFORMANCE TESTING REQUIREMENTS

- Initial compliance with this subpart must be demonstrated by complying with the standards in 40 CFR §60.5410b(k) for fugitive emissions components affected facilities [40 CFR §60.5397b(a), (i), 40 CFR § 60.5410b(k)]
- Continuous compliance with this subpart must be demonstrated by complying with the standards in 40 CFR §60.5415b(l) for fugitive emissions components affected facilities [40 CFR §60.5397b(a), (j)]

RECORDKEEPING AND REPORTING REQUIREMENTS

Notifications for well closures shall be submitted as specified in 40 CFR §60.5420b(a)(4)].

For fugitive emission components affected facilities, the following requirements shall be met:

- The applicable recordkeeping requirements as specified in 40 CFR §60.5420b(c)(14) [40 CFR §60.5397b(a), (k), 40 CFR §60.5420b(c)].
- The applicable reporting requirements as specified in 40 CFR §60.5420b(b)(1) and (9) [40 CFR §60.53397b(a), (k), 40 CFR §60.5420b(b)].

- If the alternative GHG and VOC standards for fugitive emission components affected facilities are chosen, the additional recordkeeping and reporting requirements under 40 CFR 60.5424b must be met.

PROCESS UNIT EQUIPMENT REQUIREMENTS AT ONSHORE NATURAL GAS PROCESSING PLANTS

The requirements under 40 CFR §60.5400b apply to fugitive emissions components at onshore natural gas processing plants. As previously stated, the proposed project would not trigger applicability to these requirements because this is a well affected facility.

ADEM Admin. Code r. 335-3-11 | 40 CFR 63, *"National Emission Standards for Hazardous Air Pollutants* [NESHAPS] "

This chapter covers standards under 40 CFR, Part 61 and Appendices, designated in rules 335-3-11-.02 and 335-3-11-.03 and 40 CFR Part 63, and Appendices designated in rules 335-3-11-.06 and 335-3-11-.07 are incorporated by reference as they exist in 40 CFR 61 (2021), and 40 CFR 63 (July 1, 2024), 89 FR 70505 [08/30/2024; amendments to Subpart ZZZZ], 89 FR 73293 [09/10/2024; amendments to Subpart A], 89 FR 84291 [10/22/2024; amendments to Subparts HH], and 90 FR 1040 [01/07/2025; amendments to Subpart A] , as amended by the word or phrase substitutions given in rule 335-3-11-.04. If any conflicts exist between the regulations contained in this Chapter and regulations contained in other Chapters, the more stringent regulation will take precedence.

ADEM Admin. Code r. 335-3-11-.06(1) | 40 CFR 63 Subpart A, "*General Provisions*"

The requirements under this subpart are subject by reference in an applicable subpart [40 CFR §63.1].

ADEM Admin. Code r. 335-3-11-.06(33) | *40 CFR 63 Subpart HH, "National Emission Standards for Hazardous Air Pollutants (HAPs) from Oil and Natural Gas Production Facilities" (MACT HH)*

This subpart applies to affected sources that are located at oil and natural gas production facilities and that meet the applicable criteria in 40 CFR §63.760(a). The requirements under this subpart apply to sources that are either a major source of HAPs or an area source of HAPs that either process, upgrade, or store hydrocarbon liquids and/or 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.

Affected sources for a major source under MACT HH are as follows [40 CFR §63.2, 40 CFR §63.760(b)]:

- Each glycol dehydration unit [40 CFR §63.760(b)(1)(i)];
- Each storage vessel with the potential for flash emissions [40 CFR §63.760(b)(1)(ii)];
- The group of all ancillary equipment, except compressors, intended to operate in volatile hazardous air pollutant service (as defined in 40 CFR § 63.761), which are located at natural gas processing plants [40 CFR §63.760(b)(1)(iii)];
- Compressors intended to operate in volatile hazardous air pollutant service (as defined in 40 CFR §63.761), which are located at natural gas processing plants.

The definition of a major source under 40 CFR §63.2 of Subpart A means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 TPY or more of any HAP or 25 TPY or more of any combination of HAPs. To determine if emissions from the proposed well will trigger compliance with major source requirements under this subpart, HAP emissions from the ATIC 34-12 and the Barnett Plant will not

be aggregated together with the 33-8 Well, even though the emission points are in a contiguous area and under common control. To determine major source status for production field facilities (facilities located prior to the point of custody transfer), only HAP emissions from a glycol dehydration unit and storage vessels with the potential for flash emissions shall be aggregated [40 CFR §63.2, 40 CFR §63.761].

The 33-8 Well will not be equipped with a glycol dehydration unit; however, it will have a storage vessel, with the potential for flash emissions, that would be an affected facility under this subpart [40 CFR §63.760(b)(1)(ii), 40 CFR §63.761]. The 500-barrel power oil storage vessel (T-07) will have the potential for flash emissions (see Table 7 above). Pruet has requested to limit emissions from the storage vessels with the potential for flash emissions in order to avoid being a major source of HAPs emission under this subpart. If controls are considered (the gas will be collected via a vapor recovery system and burned in the flare or routed to the end user), the emissions from the T-07 storage vessel would be zero (less than the major source thresholds for HAPs). Pruet will maintain HAPs emissions for the 33-8 Well below major source requirements by maintaining the covers and controls on all storage vessels with the potential for flash emissions.

The aggregated controlled emission from the storage vessel with flash emissions would be below the major source threshold; therefore, the 33-8 Well would be an area source of HAPs with respect to this subpart. An area source of HAPs by definition is not a major source of HAPS and an affected facility at an area source of HAPs includes a tri-ethylene glycol (TEG) dehydration unit. The proposed well will not be equipped with a TEG; therefore, it will not have an affected facility under MACT HH [40 CFR §63.761, 40 CFR §63.760(b)(2), 40 CFR §63.760(d)].

ADEM Admin. Code r. 335-3-11-.06(103) | 40 CFR 63 Subpart ZZZZ, "National Emission Standards for Hazardous Air Pollutant (HAP) for Stationary Reciprocating Internal Combustion Engines (RICE)" [aka RICE MACT]

This subpart applies to a major source of HAP or an area source of HAP. As shown in Table 2, the uncontrolled emissions from the proposed 33-8 Well based on all gases venting to atmosphere would result in the total HAP emission from the facility greater than 25 TPY. However, the facility will only operate when the gas from the well can be processed and treated and routed to a sales line to the end user. The gas would only be combusted in the facility flare under certain circumstances. When the gas is routed to the flare (Table 3, controlled emissions) or routed to the process (Table 4, expected emissions), total HAPs emissions would be less than the major source threshold. Therefore, the facility would be an area source of HAPs under this subpart.

40 CFR §63.6590(c)(1) requires that a new or reconstructed stationary RICE located at an area source of HAPs must meet the requirement under this subpart by complying with 40 CFR 60 Subpart JJJJ for spark ignition engines. There are no further requirements under this subpart [40 CFR §63.6590].

ADEM Admin. Code r. 335-3-14-.04, "Prevention of Significant Deterioration (PSD) Permitting"

Based on the facility-wide emissions found in Table 5, uncontrolled facility-wide emissions of VOC for the wellsite would be greater than 250 TPY major source threshold for this type of facility (oil wells and their associated equipment are not one of the 28 source categories listed in Rule 335-3-14-.04). In order to limit emissions for this facility below the PSD threshold, Pruet has requested to maintain the facility-wide VOC emission limit from all affected facilities to 99 Tons per 12 consecutive rolling months. Therefore, a PSD review will not be warranted for this project.

ADEM Admin. Code r. 335-3-14-.06, "Determination's for Major Sources in Accordance with Clean Air Act Section 112(g)"

HAP emissions greater than 10 TPY of any single HAP or 25 TPY of any combination of HAPs would not be expected from the combined affected facilities after the gas vapors from the separator and tanks are captured and routed to the process; therefore, a 112(g) case by case MACT review would not be required.

ADEM Admin. Code r. 335-3-15, "Synthetic Minor Operating Permits (SMOP)"

A synthetic minor source means a source whose potential to emit is restricted to less than a major source threshold as defined in Chapter 335-3-16. Based on the emissions from all sources at the proposed Barnett Area No. 1 found in Table 5, this project has the potential to emit greater than 100 tons per year for VOC and CO and greater than 10 TPY for a single HAPs or 25 TPY for a combination of HAP. However, Pruet will reduce emissions for the facility below both major source thresholds by collecting all gas vapors and routing them to a system for processing, treatment, and for sale to an end user, rather than burning the gas in the well flares (see expected facility-wide emissions in Table 4). Pruet has requested a limit of 99 tons for VOC and CO emissions per 12 consecutive rolling month average. The facility has also requested to limit HAPs emission below 9.5 tons per year for a single HAP and below 24.5 TPY for a combination of HAPs in order to maintain a minor source under this regulation.

Pruet will be required to calculate emissions from each emission source monthly, maintain emissions based on a 12-month rolling average, and maintain a record of deviations any time an emissions standard, limit, or permit requirement is not met. Per ADEM Admin. Code r. 335-3-16-.01(1)(q)2.(xxvii), fugitive emissions must be included as part of the calculations since the facility is regulated by a standard promulgated under Chapter 10 (NSPS OOOOb) and Chapter 11 (MACT ZZZZ). Pruet would also be required to submit a semi-annual report to report any deviations from a permit condition during the six-month calendar period from January 1 – June 30 and from July 1-December 31. A 15-day public comment period will be required for this project.

ADEM Admin. Code r. 335-3-16, "Major Source Operating Permits"

To become a major source under this regulation, the facility must have the potential to emit greater than 100 TPY of a regulated air pollutant, 10 TPY of a single HAP, or 25 TPY of a combination of HAPs. Based on the potential uncontrolled emissions found in Table 5, the facility has the potential to exceed the major source thresholds for CO, VOC, and for HAPs. Even though the uncontrolled facility-wide emissions has increased by the addition of the proposed 33-8 Well, Pruet is still able to maintain the emissions from this project below the major source thresholds by processing the gas rather than burning it in the flare and maintaining the control on the engine (see expected emissions in Table 4). Provided that the gas plant is not operational, Pruet will shut in the well in rather than flaring the gas although flaring is allowed under certain circumstance under 40 CFR 60 Subpart OOOOb.

CLASS 1 AREA

The nearest Class I Area would be the Breton Wildlife Refuge. However, the facility is located more than 100 km from this area.

RECOMMENDATIONS

I recommend that the Department issue Synthetic Minor Operating Permit No. 103-0046-X002 to Pruet Production Company to add the proposed ATIC 33-8 Well to the existing ATIC 34-12 and Barnett Plant. The wells and gas plant will be designated as the Barnett Area No. 1 Well. The owner/operator should be able to comply with all federal and state rules and regulations for this project. Once the 15-day public comment period has ended and comments, if any are received and have been addressed, Pruet will be issued SMOP No. 103-0046-X002.

_____
Harlotte Bolden-Wright
Industrial Minerals Section
Energy Branch
Air Division

November 12, 2026
Draft Date

ATTACHMENT A: FACILITY-WIDE CALCULATIONS

UNCONTROLLED ENGINE CALCULATIONS-BARNETT PLANT

DATA:			
		Engine	
ENGINE TYPE	=	4SRB	NG
FUEL HEAT CONTENT	=	993	Btu/Scf
FUEL H2S CONTENT	=	0.0	gr/100scf
MAXIMUM ENGINE HP	=	202	HP
ENGINE OP HOURS	=	8,760	Hr
ENGINE RATING	=	1.83	MMBtu/hr
BRAKE-SPECIFIC FUEL CONSUMPTION	=	9,075	Btu/ HP-hr
CALCULATION BASIS	=	Uncontrolled	

EMISSION FACTORS (EF)		MANUFACTURER'S EF Uncontrolled		Controlled	
NO_X	=		g/HP-hr	1	g/HP-hr
CO	=		g/HP-hr	2	g/HP-hr
VOC	=		g/HP-hr	0.37	g/HP-hr
CH_2O	=		g/HP-hr	0.19	g/HP-hr
PM	=		g/HP-hr		g/HP-hr
CH_4	=		g/HP-hr		g/HP-hr

assume 2:1 NOX to NMHC

AP-42 Ch. 3.2 & 3.3 Emission Factors (lb/MMBtu)

Type	PM_{filt}	PM_{con} [2]	SO_2 [1]	NO_X	CO	VOC	CH_2O	Other HAPs
Diesel	3.10E-1	2.02E-1	[By Mass]	4.41E+0	9.50E-1	3.50E-1	1.18E-3	2.69E-3
2SLB	3.84E-2	9.91E-3	5.88E-4	3.17E+0	3.86E-1	1.20E-1	5.52E-2	2.53E-2
4SLB	7.71E-5	9.91E-3	5.88E-4	4.08E+0	3.17E-1	1.18E-1	5.28E-2	2.10E-2
4SRB	9.50E-3	9.91E-3	5.88E-4	2.27E+0	3.72E+0	2.96E-2	2.05E-2	1.20E-2

40 CFR Part 98 Subpart C Greenhouse Gas Emission Factors
Tables C-1 & C-2
(kg/MMBtu)

	N_2O	CO_2	CH_4
Diesel	0.0006	75.04	0.003
NG	0.0001	53.06	0.001
LPG	0.0006	62.72	0.003
Propane	0.0006	61.46	0.003

GWP	
N_2O=	298
CO_2=	1
CH_4=	25

Uncontrolled 202 HP Engine Emissions Calculations

											Uncontrolled
$PM_{1,filt}$	9.50E-3 lb / MMBtu	1.83 MMBtu / hr		8,760 Hr / Year	1 Ton / 2000 Lb				=		0.076 Tons / Year
PM_{con}	9.91E-3 lb / MMBtu	1.83 MMBtu / hr		8,760 Hr / Year	1 Ton / 2000 Lb				=		0.080 Tons / Year
SO_2	0.0006 lb / MMBtu	1.83 MMBtu / Hr	8760 Hrs / Year	1 Ton / 2000 Lb		S.F.	0.0 gr/100scf / 0.2 gr/100scf		=		0.00 Tons / Year
NO_X	2.27E+0 lb / MMBtu	1.83 MMBtu / hr		8,760 Hr / Year	1 Ton / 2000 Lb			S.F.	=		18.23 Tons / Year
CO	3.72E+0 lb / MMBtu	1.83 MMBtu / hr		8,760 Hr / Year	1 Ton / 2000 Lb			S.F.	=		29.87 Tons / Year
VOC	0.03 lb / MMBtu	1.83 MMBtu / hr		8,760 Hr / Year	1 Ton / 2000 Lb			S.F.	=		0.24 Tons / Year
CH_2O	0.0205 lb / MMBtu	1.83 MMBtu / hr		8,760 Hr / Year	1 Ton / 2000 Lb			S.F.	=		0.16 Tons / Year
non-CH_2O HAPs	0.0120 lb / MMBtu	1.83 MMBtu / Hr		8,760 Hr / Year	1 Ton / 2000 Lb			S.F.	=		0.10 Tons / Year
CO_2	1.83 MMBtu / Hr	53.06 kg / MMBtu	0.001 Metric Ton / kg	8,760 Hr / Year		1.1023 Tons / 1 M Ton			=		939.23 Tons / Year
N_2O	1.83 MMBtu / Hr	0.0001 kg / MMBtu	0.001 Metric Ton / kg	8,760 Hr / Year		1.1023 Tons / 1 M Ton			=		0.00 Tons / Year
CH_4	1.83 MMBtu / Hr	0.001 kg / MMBtu	0.001 Metric Ton / kg	8,760 Hr / Year		1.1023 Tons / 1 M Ton			=		0.02 Tons / Year
Mass Sum	939.23 Tons / Year (CO_2)	+	0.0018 Tons / Year (N_2O)	+	0.0177 Tons / Year (CH_4)				=		939.25 Tons / Year
CO_2e	939.23 TPY*1 / 939.23 / CO_2	+	0.0018 TPY*298 / 0.53 / N_2O	+	0.018 TPY*25 / 0.44 / CH_4				=		940.20 Tons / Year

[1] EPA AP-42 factors assume gas to have 2000 gr S/MMScf (at EPA STP). AP-42 factor can be corrected to sulfur value of facility gas by comparing actual sulfur values to EPA reference point.

[2] EPA AP-42 Ch. 3.3 & 3.4 factors account only for filterable particulate matter. In absence of PMcon factors for engines, applying ratio of PMfilt to PMcon factors from AP-42 Ch. 1.3 (for diesel) to PMfilt factors from Ch. 3.3 & 3.4

CONTROLLED ENGINE EMISSIONS- BARNETT PLANT

DATA:		Engine	
ENGINE TYPE	=	4SRB	NG
FUEL HEAT CONTENT	=	993 Btu/Scf	
FUEL H2S CONTENT	=	0.0 gr/100scf	
MAXIMUM ENGINE HP	=	202 HP	
ENGINE OP HOURS	=	8,760 Hr	
ENGINE RATING	=	**1.83** MMBtu/hr	
BRAKE-SPECIFIC FUEL CONSUMPTION	=	9,075 Btu/ HP-hr	
CALCULATION BASIS	=	**Controlled**	

EMISSION FACTORS (EF)		MANUFACTURER'S EF Controlled	
NO_X	=	1 g/HP-hr	g/HP-hr
CO	=	2 g/HP-hr	g/HP-hr
VOC	=	0.37 g/HP-hr	g/HP-hr
CH_2O	=	0.19 g/HP-hr	g/HP-hr
PM	=	g/HP-hr	g/HP-hr
CH_4	=	g/HP-hr	g/HP-hr

AP-42 Ch. 3.2 & 3.3 Emission Factors (lb/MMBtu)

Type	PM_{filt}	PM_{con}[2]	SO_2[1]	NO_X	CO	VOC	CH_2O	Other HAPs
Diesel	3.10E-1	2.02E-1	[By Mass]	4.41E+0	9.50E-1	3.50E-1	1.18E-3	2.69E-3
2SLB	3.84E-2	9.91E-3	5.88E-4	3.17E+0	3.86E-1	1.20E-1	5.52E-2	2.53E-2
4SLB	7.71E-5	9.91E-3	5.88E-4	4.08E+0	3.17E-1	1.18E-1	5.28E-2	2.10E-2
4SRB	9.50E-3	9.91E-3	5.88E-4	2.27E+0	3.72E+0	2.96E-2	2.05E-2	1.20E-2

40 CFR Part 98 Subpart C Greenhouse Gas Emission Factors
Tables C-1 & C-2
(kg/MMBtu)

	N_2O	CO_2	CH_4
Diesel	0.0006	75.04	0.003
NG	0.0001	53.06	0.001
LPG	0.0006	62.72	0.003
Propane	0.0006	61.46	0.003

GWP	
N_2O=	298
CO_2=	1
CH_4=	25

assume 2:1 NOX to NMHC

Controlled 202 HP Engine Emissions Calculations

										Controlled
$PM_{1,filt}$	0.0095 lb / MMBtu	1.83 MMBtu / hr		8,760 Hr / Year	1 Ton / 2000 Lb			=		**0.08 Tons / Year**
PM_{con}	0.00991 lb / MMBtu	1.83 MMBtu / hr		8,760 Hr / Year	1 Ton / 2000 Lb			=		**0.08 Tons / Year**
SO_2	0.0006 lb / MMBtu	1.83 MMBtu / Hr	8760 Hrs / Year	1 Ton / 2000 Lb		S.F.	0.0 gr/100scf / 0.2 gr/100scf	=		**0.00 Tons / Year**
NO_X	1 g / HP-Hr	202.00 HP	1 Lb / 453.6 g	8,760 Hr / Year	1 Ton / 2000 Lb		S.F.	=		**1.95 Tons / Year**
CO	2 g / HP-Hr	202.00 HP	1 Lb / 453.6 g	8,760 Hr / Year	1 Ton / 2000 Lb		S.F.	=		**3.90 Tons / Year**
VOC	0.37 g / HP-Hr	202.00 HP	1 Lb / 453.6 g	8,760 Hr / Year	1 Ton / 2000 Lb		S.F.	=		**0.72 Tons / Year**
CH_2O	0.1900 g / HP-Hr	202.00 HP	1 Lb / 453.6 g	8,760 Hr / Year	1 Ton / 2000 Lb		S.F.	=		**0.37 Tons / Year**
non-CH_2O HAPs	0.0120 lb / MMBtu	1.83 MMBtu / Hr		8,760 Hr / Year	1 Ton / 2000 Lb		S.F.	=		**0.10 Tons / Year**
CO_2	1.83 MMBtu / Hr	53.06 kg / MMBtu	0.001 Metric Ton / kg	8,760 Hr / Year		1.1023 Tons / 1 M Ton		=		**939.23 Tons / Year**
N_2O	1.83 MMBtu / Hr	0.0001 kg / MMBtu	0.001 Metric Ton / kg	8,760 Hr / Year		1.1023 Tons / 1 M Ton		=		**0.00 Tons / Year**
CH_4	1.83 MMBtu / Hr	0.001 kg / MMBtu	0.001 Metric Ton / kg	8,760 Hr / Year		1.1023 Tons / 1 M Ton		=		**0.02 Tons / Year**
Mass Sum	939.23 Tons / Year / CO_2	+	0.0018 Tons / Year / N_2O	+	0.0177 Tons / Year / CH_4			=		**939.25 Tons / Year**
CO_2e	939.23 TPY*1 / 939.23 / CO_2	+	0.0018 TPY*298 / 0.53 / N_2O	+	0.018 TPY*25 / 0.44 / CH_4			=		**940.20 Tons / Year**

[1] EPA AP-42 factors assume gas to have 2000 gr S/MMScf (at EPA STP). AP-42 factor can be corrected to sulfur value of facility gas by comparing actual sulfur values to EPA reference point.

[2] EPA AP-42 Ch. 3.3 & 3.4 factors account only for filterable particulate matter. In absence of PMcon factors for engines, applying ratio of PMfilt to PMcon factors from AP-42 Ch. 1.3 (for diesel) to PMfilt factors from Ch. 3.3 & 3.4

FLARE CALCULATIONS- ATIC 34-12 Well

Data	Total		Separator Gas		Tank Gas		Pilot Gas		GWP (11/29/2013)		40 CFR Part 98 Sub C GHG Emission Factors (Table C-1)		
Volume	38,814.167	scf/hr (Ind.)	852.0	Mscf/day	72.5	Mscf/day	7.0	Mscf/day	N_2O=	298	N_2O=	0.0001	kg/MMBtu
H_2S mol%	0.0011%	mol%	0.0012%	mol%	0.0000%	mol%	0.0000%	mol%	CO_2=	1	AP 42 Emissions Factors[7]		
Heat Content	1189.62	Btu/scf (Ind)	1107.00	Btu/scf (Ind)	2179.00	Btu/scf (Ind)	993.30	Btu/scf (Ind)	CH_4=	25			
VOC MW	6.21	lb/lb-mol[2]	4.47	lb/lb-mol[2]	27.16	lb/lb-mol[2]	1.69	lb/lb-mol[2]			NO_x=	0.068	lb/MMBtu
CO_2	1.07%	mol%	1.14%	mol%	0.18%	mol%	1.22%	mol%			CO=	0.37	lb/MMBtu
CH_4	68.02%	mol%	71.19%	mol%	30.03%	mol%	76.30%	mol%			PM_1=	40	µg/L
C_6	0.19	lb/lb-mol[2]	0.19	lb/lb-mol[2]	2.51	lb/lb-mol[2]	1.03	lb/lb-mol[2]					
OP Hours	8760	Hrs							(Ind. STP)	scf/lbmol= 371.17	60 °F	15.025	psia
Destruction Eff	98.00%	DRE	Heat Input		46.17	MMBtu/hr[1]			(EPA STP)	scf/lbmol= 385.5	68 °F	14.696	psia

Potential Flare Emission Calculations

Pollutants														CONTROLLED		UNCONTROLLED	
PM_1	40 µg / L		38814.2 scf (Ind.) / Hr		2.2E-9 lb / µg		8,760 Hr / Year		1 Ton / 2,000 Lb		28.31685 L / scf (EPA)	1.04 scf(EPA) / 1 scf(Ind.)	=	0.441 Tons / Year		0.441 Tons / Year	
SO_2	172.6 Lb SO_2[4] / MScf (Ind.)		38.814 MScf (Ind.) / Hr		0.001% H_2S Mol%		8,760 Hr / Year				1 Ton / 2,000 Lb		=	0.322 Tons / Year		0.322 Tons / Year	
NO_x	0.068 lb / MMBtu		46.174 MMBtu / Hr		8,760 Hr / Year		1 Ton / 2,000 Lb						=	13.753 Tons / Year		13.753 Tons / Year	
CO	0.37 lb / MMBtu		46.174 MMBtu / Hr		8,760 Hr / Year		1 Ton / 2,000 Lb						=	74.830 Tons / Year		74.830 Tons / Year	
VOC[5]	38,814.2 Scf (Ind.) / Hr		1 lb-mol / 371.17 scf (Ind.)		6.21 Lb VOC / Lb-Mole		8,760 Hr / Year		1 Ton / 2,000 Lb	2.00%	Inv. DRE		=	56.899 Tons / Year		2,844.97 TPY	
HAPs[8]	38,814.2 Scf (Ind.) / Hr		1 lb-mol / 371.17 scf (Ind.)		0.19 Lb C_6 / Lb-Mole		8,760 Hr / Year		1 Ton / 2,000 Lb	2.00%	Inv. DRE		=	1.768 Tons / Year		88.42 TPY	
CO_2 of Combustion[5,6]	98.00% DRE	3.40E+08 Scf (Ind.) / Yr		1.28 lb-mol CO_2 (stoich.) / 1 lb-mol gas (stoich.)		1 lb-mol gas / 371.17 scf (Ind.)		44.01 lb CO_2 / lb-mole CO_2		1 Ton / 2,000 Lb			=	25,221.58 Tons / Year		25,736.31 TPY	
CO_2 of Fuel	3.40E+08 Scf (Ind.) / Yr		1.07% mol% CO_2		1 lb-mol / 371.17 scf (Ind.)		44.01 Lb CO2 / Lb-mole		1 Ton / 2,000 Lb				=	215.19 Tons / Year			
N_2O	0.001 M Ton / kg	0.001190 MMBtu / Scf (Ind.)		38,814.2 Scf (Ind.) / Hr		0.0001 kg / MMBtu		8,760 Hr / Year		1.1023 Tons / 1 Metric Ton			=	0.0446 Tons / Year			
CH_4 Uncombusted	3.40E+08 Scf (Ind.) / Yr		2.00%	Inv. DRE	68.02%	mol% CH_4	1 lb-mol / 371.174 scf (Ind.)		16.043 Lb CH4 / Lb-mole		1 Ton / 2,000 Lb		=	99.96 Tons / Year		4,998.16 TPY	
Mass Sum	25,436.77 Tons / Year (CO2)		+		0.0446 Tons / Year (N2O)		+		99.96 Tons / Year (CH4)				=	25,536.78 Tons / Year		30,949.702 TPY	
CO_2e	25,436.77 TPY (CO2)	X 1 = 25,436.77	+		0.0446 TPY (N2O)	X 298 = 13.29	+		99.96 TPY (CH4)	X 25 = 2,499.08			=	27,949.14 Tons / Year		150,918.84 TPY	

[1] Rated Heat Capacity (MMBtu/Hr) = Flowrate (Scf/Hr) * Heat Content (Btu/Scf) * (MMBtu/10^6 Btu)

[2] VOC (Lb/Lb-mole) = Σ(Mole% of Each Compound)* (1%/100)*MW of Each Compound) -See Flare GHG Spreed Sheet for gas analysis

[3] Has to be maintained <500 lb/hr or 20 ppbv offsite concentration could potentially be exceeded

H_2S (Lb/hr) = Volume (Scf/hr) * (1 lb-mol/380.67) *(H_2S mol%) * (34.08 Lb H_2S/Lb-mol)

[4] SO_2 Conversion Factor 168.3 Lb SO_2/MScf of Gas

=(1,000 Scf/MScf) *(1Lb-Mole/380.67 Scf)* (64.066 Lb SO_2/Lb-Mole)

[5] Assuming the flare is 98% efficient

[6] Calculated using the gas analysis:

$\Sigma\ Y_j * R_j$ where, Y_j= mole fraction of gas hydrocarbon constituents' j (such as methane, ethane, propane, carbon dioxide, etc.) and R_j= number of carbon atoms in gas hydrocarbon constituent j: 1 for methane and carbon dioxide, 2 for ethane, 3 for propane, etc.

[7] Flare assumed to be "lightly smoking" in AP-42 table 13.5-1

[8] n-Hexane, Benzene, Toluene, etc are HAPs, but i-Hexanes, n-Heptane, n-Octane, etc are not. Assume by mass 50% Hexanes and 10% Heptanes+ are HAPS

FLARE CALCULATIONS- ATIC 33-8 Well

Data	Total		Separator Gas		Tank Gas		Pilot Gas	
Volume	**47,023.542**	scf/hr (Ind.)	1025.0	Mscf/day	72.5	Mscf/day	31.0	Mscf/day
H_2S mol%	0.0012%	mol%	0.0012%	mol%	0.0012%	mol%	0.0010%	mol%
Heat Content	1175.90	Btu/scf (Ind)	1107.00	Btu/scf (Ind)	2179.00	Btu/scf (Ind)	1107.00	Btu/scf (Ind)
VOC MW	**5.92**	lb/lb-mol[2]	**4.47**	lb/lb-mol[2]	**27.16**	lb/lb-mol[2]	**4.46**	lb/lb-mol[2]
CO_2	**1.08%**	mol%	**1.14%**	mol%	**0.18%**	mol%	**1.14%**	mol%
CH_4	**68.54%**	mol%	**71.19%**	mol%	**30.03%**	mol%	**71.19%**	mol%
C_6	**0.29**	lb/lb-mol[2]	**0.19**	lb/lb-mol[2]	**1.78**	lb/lb-mol[2]	**0.19**	lb/lb-mol[2]
OP Hours	8760	Hrs						
Destruction Eff	**98.00%**	DRE	Heat Input		**55.30**	MMBtu/hr[1]		

GWP (4/25/2024)		
N_20=	265	
CO_2=	1	
CH_4=	28	
Table A-1 Subpart A, Part		

40 CFR Part 98 Sub C GHG Emission Factors (Table C-1)		
N_20=	0.0001	kg/MMBtu
AP 42 Emissions Factors[7]		
NO_X=	0.068	lb/MMBtu
CO=	0.37	lb/MMBtu
PM_1=	40	µg/L

(Ind. STP)	scf/lbmol=	371.17	60	°F	15.025	psia
(EPA STP)	scf/lbmol=	385.5	68	°F	14.696	psia

Potential Flare Emission Calculations

Pollutants															CONTROLLED	UNCONTROLLED	
PM_1	40	µg	47023.5	scf (Ind.)	2.2E-9 lb	8,760 Hr	1 Ton	28.31685 L	1.04	scf(EPA)	=	**0.534**	Tons	**0.534**	Tons
	L		Hr		µg	Year	2,000 Lb	scf (EPA)	1	scf(Ind.)		Year		Year	
SO_2	172.6	Lb SO_2[4]	47.024	MScf (Ind.)	0.001%	H_2S Mol%	8,760 Hr	1 Ton			=	**0.425**	Tons	**0.425**	Tons
	MScf (Ind.)		Hr				Year	2,000 Lb				Year		Year	
NO_X	0.068	lb	55.295	MMBtu	8,760 Hr		1 Ton				=	**16.469**	Tons	**16.469**	Tons
	MMBtu		Hr		Year		2,000 Lb					Year		Year	
CO	0.37	lb	55.295	MMBtu	8,760 Hr		1 Ton				=	**89.611**	Tons	**89.611**	Tons
	MMBtu		Hr		Year		2,000 Lb					Year		Year	
VOC[5]	47,023.5	Scf (Ind.)	1	lb-mol	5.92	Lb VOC	8,760 Hr	1 Ton	2.00%	Inv. DRE	=	**65.740**	Tons	**3,287.01**	TPY
	Hr		371.17	scf (Ind.)	Lb-Mole		Year	2,000 Lb				Year			
HAPs[8]	47,023.5	Scf (Ind.)	1	lb-mol	0.19	Lb C_6	8,760 Hr	1 Ton	2.00%	Inv. DRE	=	**2.142**	Tons	**107.12**	TPY
	Hr		371.17	scf (Ind.)	Lb-Mole		Year	2,000 Lb				Year			
CO_2[5,6] of Combustion	98.00% DRE		4.12E+08	Scf (Ind.)	1.26	lb-mol CO_2 (stoich.)	1 lb-mol gas	44.01 lb CO_2		1 Ton	=	**30,147.14**	Tons	**30,762.39**	TPY
			Yr		1	lb-mol gas (stoich.)	371.17 scf (Ind.)	lb-mole CO_2		2,000 Lb		Year			
CO_2 of Fuel	4.12E+08	Scf (Ind.)	1.08%	mol% CO_2	1 lb-mol		44.01 Lb CO2	1 Ton			=	**263.74**	Tons		
	Yr				371.17 scf (Ind.)		Lb-mole	2,000 Lb				Year			
N_2O	0.001 M Ton		0.001176 MMBtu		47,023.5 Scf (Ind.)		0.0001 kg	8,760 Hr		1.1023 Tons	=	**0.0534**	Tons		
	kg		Scf (Ind.)		Hr		MMBtu	Year		1 Metric Ton		Year			
CH_4 Uncombusted	4.12E+08	Scf (Ind.)	2.00%	Inv. DRE	68.54%	mol% CH_4	1 lb-mol	16.043 Lb CH4		1 Ton	=	**122.03**	Tons	**6,101.69**	TPY
	Yr						371.174 scf (Ind.)	Lb-mole		2,000 Lb		Year			
Mass Sum	30,410.88 Tons			+	0.0534 Tons		+	122.03 Tons			=	**30,532.97**	Tons	**37,127.876**	TPY
	Year				Year			Year				Year			
	CO2				N2O			CH4							
CO_2e	30,410.88 TPY	X 1			0.0534 TPY	X 265		122.03 TPY	X 28		=	**33,841.98**	Tons	**183,584.31**	TPY
	30,410.88			+	14.15		+	3,416.95				Year			
	CO2				N2O			CH4							

[1] Rated Heat Capacity (MMBtu/Hr) = Flowrate (Scf/Hr) * Heat Content (Btu/Scf) * (MMBtu/10^6 Btu)

[2] VOC (Lb/Lb-mole) = Σ(Mole% of Each Compound)* (1%/100)*MW of Each Compound) -See Flare GHG Spreed Sheet for gas analysis

[3] Has to be maintained <500 lb/hr or 20 ppbv offsite concentration could potentially be exceeded

H_2S (Lb/hr) = Volume (Scf/hr) * (1 lb-mol/380.67) *(H_2S mol%) * (34.08 Lb H_2S/Lb-mol)

[4] SO_2 Conversion Factor 168.3 Lb SO_2/MScf of Gas

=(1,000 Scf/MScf) *(1Lb-Mole/380.67 Scf)* (64.066 Lb SO_2/Lb-Mole)

[5] Assuming the flare is 98% efficient

[6] Calculated using the gas analysis:

$\Sigma Y_j * R_j$ where, Y_j= mole fraction of gas hydrocarbon constituents' j (such as methane, ethane, propane, carbon dioxide, etc.) and R_j= number of carbon atoms in gas hydrocarbon constituent j: 1 for methane and carbon dioxide, 2 for ethane, 3 for propane, etc.

[7] Flare assumed to be "lightly smoking" in AP-42 table 13.5-1

[8] n-Hexane, Benzene, Toluene, etc are HAPs, but i-Hexanes, n-Heptane, n-Octane, etc are not. Assume by mass 50% Hexanes and 10% Heptanes+ are HAPS

SEPARATOR CALCULATIONS- ATIC 34-12 WELL

Data	Total		Separator Gas		Tank Gas		Pilot Gas	
Volume	**35,500.000**	scf/hr (Ind.)	**852.0**	Mscf/day		Mscf/day		Mscf/day
H_2S mol%	0.0012%	mol%	0.0012%	mol%		mol%		mol%
Heat Content	1107.00	Btu/scf (Ind)	1107.00	Btu/scf (Ind)		Btu/scf (Ind)		Btu/scf (Ind)
VOC MW	**4.47**	lb/lb-mol[2]	**4.47**	lb/lb-mol[2]		lb/lb-mol[2]		lb/lb-mol[2]
CO_2	**1.14%**	mol%	**1.14%**	mol%		mol%		mol%
CH_4	**71.19%**	mol%	**71.19%**	mol%		mol%		mol%
C_6	**0.19**	lb/lb-mol[2]	**0.19**	lb/lb-mol[2]		lb/lb-mol[2]		lb/lb-mol[2]
OP Hours	8760	Hrs						
Destruction Eff	**98.00%**	DRE	Heat Input		**39.30**	MMBtu/hr[1]		

GWP (11/29/2013)	
N_20=	298
CO_2=	1
CH_4=	25

40 CFR Part 98 Sub C GHG Emission Factors (Table C-1)		
N_20=	0.0001	kg/MMBtu

AP 42 Emissions Factors[7]		
NO_X=	0.068	lb/MMBtu
CO=	0.37	lb/MMBtu
PM_1=	40	µg/L

(Ind. STP)	scf/lbmol=	380.67	60	°F	14.65	psia
(EPA STP)	scf/lbmol=	385.5	68	°F	14.696	psia

Potential Separator Emission Calculations

Pollutants															Controlled	Uncontrolled
PM_1	40 µg / L	×	35500.0 scf (Ind.) / Hr	×	2.2E-9 lb / µg	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb	×	28.31685 L / scf (EPA)	×	1.01 scf(EPA) / 1 scf(Ind.)	=	**0.393 Tons / Year**	**0.393 Tons / Year**
SO_2	168.3 Lb SO_2[4] / MScf (Ind.)	×	35.500 MScf (Ind.) / Hr	×	0.001% H_2S Mol%	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb					=	**0.314 Tons / Year**	**0.314 Tons / Year**
NO_X	0.068 lb / MMBtu	×	39.299 MMBtu / Hr	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb							=	**11.705 Tons / Year**	**11.705 Tons / Year**
CO	0.37 lb / MMBtu	×	39.299 MMBtu / Hr	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb							=	**63.687 Tons / Year**	**63.687 Tons / Year**
VOC[5]	35,500.0 Scf (Ind.) / Hr	×	1 lb-mol / 380.67 scf (Ind.)	×	4.47 Lb VOC / Lb-Mole	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb	×	2.00% Inv. DRE			=	**79.254 Tons / Year**	**3962.721 Tons / Year**
HAPs[8]	35,500.0 Scf (Ind.) / Hr	×	1 lb-mol / 380.67 scf (Ind.)	×	0.19 Lb C_6 / Lb-Mole	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb	×	2.00% Inv. DRE			=	**1.577 Tons / Year**	**78.850 Tons / Year**
CO_2[5,6] of Combustion	98.00% DRE	×	3.11E+08 Scf (Ind.) / Yr	×	1.17 lb-mol CO_2 (stoich.) / 1 lb-mol gas (stoich.)	×	1 lb-mol gas / 380.67 scf (Ind.)	×	44.01 lb CO_2 / lb-mole CO_2	×	1 Ton / 2,000 Lb			=	**20,681.71 Tons / Year**	**21,103.79 Tons / Year**
CO_2 of Fuel	3.11E+08 Scf (Ind.) / Yr	×	1.14% mol% CO_2	×	1 lb-mol / 380.67 scf (Ind.)	×	44.01 Lb CO2 / Lb-mole	×	1 Ton / 2,000 Lb					=	**205.29 Tons / Year**	**205.29 Tons / Year**
N_2O	0.001 M Ton / kg	×	0.001107 MMBtu / Scf (Ind.)	×	35,500.0 Scf (Ind.) / Hr	×	0.0001 kg / MMBtu	×	8,760 Hr / Year	×	1.1023 Tons / 1 Metric Ton			=	**0.0379 Tons / Year**	**0.0379 Tons / Year**
CH_4 Uncombusted	3.11E+08 Scf (Ind.) / Yr	×	2.00% Inv. DRE	×	71.19% mol% CH_4	×	1 lb-mol / 380.675 scf (Ind.)	×	16.043 Lb CH4 / Lb-mole	×	1 Ton / 2,000 Lb			=	**93.30 Tons / Year**	**4,664.82 Tons / Year**
Mass Sum	20,887.00 Tons / Year (CO2)	+		+	0.0379 Tons / Year (N2O)	+		+	93.30 Tons / Year (CH4)					=	**20,980.33 Tons / Year**	**25,973.93 Tons / Year**
CO_2e	20,887.00 TPY (CO2)	X	1 = 20,887.00	+	0.0379 TPY (N2O)	X	298 = 11.31	+	93.30 TP (CH4)	X	25 = 2,332.41			=	**23,230.71 Tons / Year**	**137,940.79 Tons / Year**

[1] Rated Heat Capacity (MMBtu/Hr) = Flowrate (Scf/Hr) * Heat Content (Btu/Scf) * (MMBtu/10^6 Btu)

[2] VOC (Lb/Lb-mole) = Σ(Mole% of Each Compound)* (1%/100)*MW of Each Compound) -See Flare GHG Spreed Sheet for gas analysis

[3] Has to be maintained <500 lb/hr or 20 ppbv offsite concentration could potentially be exceeded
H_2S (Lb/hr) = Volume (Scf/hr) * (1 lb-mol/380.67) *(H_2S mol%) * (34.08 Lb H_2S/Lb-mol)

[4] SO_2 Conversion Factor 168.3 Lb SO_2/MScf of Gas
=(1,000 Scf/MScf) *(1Lb-Mole/380.67 Scf)* (64.066 Lb SO_2/Lb-Mole)

[5] Assuming the flare is 98% efficient

[6] Calculated using the gas analysis:
$\Sigma Y_j * R_j$ where, Y_j= mole fraction of gas hydrocarbon constituents' j (such as methane, ethane, propane, carbon dioxide, etc.) and R_j= number of carbon atoms in gas hydrocarbon constituent j: 1 for methane and carbon dioxide, 2 for ethane, 3 for propane, etc.

[7] Flare assumed to be "lightly smoking" in AP-42 table 13.5-1

[8] n-Hexane, Benzene, Toluene, etc are HAPs, but i-Hexanes, n-Heptane, n-Octane, etc are not. Assume by mass 50% Hexanes and 10% Heptanes+ are HAPS

SEPARATOR CALCULATIONS- ATIC 33-8 WELL

Data	Total		Separator Gas		[redacted]	GWP (4/25/2024)		40 CFR Part 98 Sub C GHG Emission Factors (Table C-1)	
Volume	42,709.375	scf/hr (Ind.)	1025.0	Mscf/day		N_2O=	265	N_2O=	0.0001 kg/MMBtu
H_2S mol%	0.0012%	mol%	0.0012%	mol%		CO_2=	1	AP 42 Emissions Factors[7]	
Heat Content	1107.00	Btu/scf (Ind)	1107.00	Btu/scf (Ind)		CH_4=	28	NO_x=	0.068 lb/MMBtu
VOC MW	4.47	lb/lb-mol[2]	4.47	lb/lb-mol[2]				CO=	0.37 lb/MMBtu
CO_2	1.14%	mol%	1.14%	mol%				PM_1=	40 µg/L
CH_4	71.19%	mol%	71.19%	mol%					
C_6	0.19	lb/lb-mol[2]	0.19	lb/lb-mol[2]					
OP Hours	8760	Hrs				(Ind. STP)	scf/lbmol= 371.17	60 °F	15.025 psia
Destruction Eff	98.00%	DRE	Heat Input	47.28	MMBtu/hr[1]	(EPA STP)	scf/lbmol= 385.5	68 °F	14.696 psia

Potential Separator Emission Calculations

Pollutants																Controlled	Uncontrolled
PM_1	40 µg / L		42709.4 scf (Ind.) / Hr		2.2E-9 lb / µg		8,760 Hr / Year		1 Ton / 2,000 Lb	28.31685 L / scf (EPA)		1.04 scf(EPA) / 1 scf(Ind.)		=	0.485 Tons / Year	0.485 Tons / Year
SO_2	172.6 Lb SO_2[4] / MScf (Ind.)		42.709 MScf (Ind.) / Hr		0.001% H_2S Mol%		8,760 Hr / Year		1 Ton / 2,000 Lb					=	0.387 Tons / Year	0.387 Tons / Year
NO_x	0.068 lb / MMBtu		47.279 MMBtu / Hr		8,760 Hr / Year		1 Ton / 2,000 Lb							=	14.082 Tons / Year	14.082 Tons / Year
CO	0.37 lb / MMBtu		47.279 MMBtu / Hr		8,760 Hr / Year		1 Ton / 2,000 Lb							=	76.621 Tons / Year	76.621 Tons / Year
VOC[5]	42,709.4 Scf (Ind.) / Hr		1 lb-mol / 371.17 scf (Ind.)		4.47 Lb VOC / Lb-Mole		8,760 Hr / Year		1 Ton / 2,000 Lb	2.00%		Inv. DRE		=	45.006 Tons / Year	2250.324 Tons / Year
HAPs[8]	42,709.4 Scf (Ind.) / Hr		1 lb-mol / 371.17 scf (Ind.)		0.19 Lb C_6 / Lb-Mole		8,760 Hr / Year		1 Ton / 2,000 Lb	2.00%		Inv. DRE		=	1.946 Tons / Year	97.291 Tons / Year
CO_2[5,6] of Combustion	98.00% DRE	3.74E+08 Scf (Ind.) / Yr		1.174 lb-mol CO_2 (stoich.) / 1 lb-mol gas (stoich.)			1 lb-mol gas / 371.17 scf (Ind.)		44.01 lb CO_2 / lb-mole CO_2			1 Ton / 2,000 Lb		=	25,518.68 Tons / Year	26,039.47 Tons / Year
CO_2 of Fuel	3.74E+08 Scf (Ind.) / Yr		1.14% mol% CO_2		1 lb-mol / 371.17 scf (Ind.)		44.01 Lb CO2 / Lb-mole		1 Ton / 2,000 Lb					=	253.30 Tons / Year	253.30 Tons / Year
N_2O	0.001 M Ton / kg	0.001107 MMBtu / Scf (Ind.)		42,709.4 Scf (Ind.) / Hr		0.0001 kg / MMBtu		8,760 Hr / Year		1.1023 Tons / 1 Metric Ton				=	0.0457 Tons / Year	0.0457 Tons / Year
CH_4 Uncombusted	3.74E+08 Scf (Ind.) / Yr		2.00%	Inv. DRE	71.19%	mol% CH_4	1 lb-mol / 371.174 scf (Ind.)		16.043 Lb CH4 / Lb-mole			1 Ton / 2,000 Lb		=	115.12 Tons / Year	5,755.81 Tons / Year
Mass Sum	25,771.98 Tons / Year (CO2)		+		0.0457 Tons / Year (N2O)		+		115.12 Tons / Year (CH4)					=	25,887.14 Tons / Year	32,048.62 Tons / Year
CO_2e	25,771.98 TPY X 1 = 25,771.98 (CO2)		+		0.0457 TPY X 265 = 12.10 (N2O)		+		115.12 TPY X 28 = 3,223.25 (CH4)					=	29,007.33 Tons / Year	187,467.48 Tons / Year

[1] Rated Heat Capacity (MMBtu/Hr) = Flowrate (Scf/Hr) * Heat Content (Btu/Scf) * (MMBtu/10^6 Btu)

[2] VOC (Lb/Lb-mole) = Σ(Mole% of Each Compound)* (1%/100)*MW of Each Compound) -See Flare GHG Spreed Sheet for gas analysis

[3] Has to be maintained <500 lb/hr or 20 ppbv offsite concentration could potentially be exceeded
H_2S (Lb/hr) = Volume (Scf/hr) * (1 lb-mol/380.67) *(H_2S mol%) * (34.08 Lb H_2S/Lb-mol)

[4] SO_2 Conversion Factor 168.3 Lb SO_2/MScf of Gas
=(1,000 Scf/MScf) *(1Lb-Mole/380.67 Scf)* (64.066 Lb SO_2/Lb-Mole)

[5] Assuming the flare is 98% efficient

[6] Calculated using the gas analysis:
$\Sigma Y_j * R_j$ where, Y_j= mole fraction of gas hydrocarbon constituents' j (such as methane, ethane, propane, carbon dioxide, etc.) and R_j= number of carbon atoms in gas hydrocarbon constituent j: 1 for methane and carbon dioxide, 2 for ethane, 3 for propane, etc.

[7] Flare assumed to be "lightly smoking" in AP-42 table 13.5-1

[8] n-Hexane, Benzene, Toluene, etc are HAPs, but i-Hexanes, n-Heptane, n-Octane, etc are not. Assume by mass 50% Hexanes and 10% Heptanes+ are HAPS

HEATER CALCULATIONS (PER WELL)

Data:					AP-42 EF (NG)			Based on NG with Btu/Content of 1020				
H_2S mol%	0.00%	mol%			PM=	7.6	Lb/MMScf		GWP*		*Revised 11/29/2013	
Op Hours	8760	Hrs			NO_X=	100	Lb/MMScf		N_2O=	298		
Heat Content	993	Btu/scf (Ind.)			CO=	84	Lb/MMScf		CO_2=	1		
Flowrate	**0.503**	MScf/Hr (Ind.)			VOC=	5.5	Lb/MMScf		CH_4=	25		
Heat Input	500,000	Btu/hr			HAP=	1.89	Lb/MMScf					
Use btu/scf(EPA) for PM, NOx, CO, VOC. Factors for EPA STP (also ADEM STP). SO2 factor already for Industry STP (from Al. Oil & Gas Board)					SO_2=	0.60	Lb/MMScf	industry				lb/MMSCF
					(Table C-1 & C-2) 40 CFR Part 98 Sub C GHG Emission Factors for C_3			(Table C-1 & C-2) 40 CFR Part 98 Sub C GHG Emission Factors for C_1			PM con	5.7
Ind. STP:	60	°F	14.65	psia							PM fil	1.9
EPA STP:	68	°F	14.696	psia	N_2O=	0.0006	kg/MMBtu	N_2O=	0.0001	kg/MMBtu		1.35799087
Heat Content	981	Btu/scf (EPA)			CO_2=	61.46	kg/MMBtu	CO_2=	53.02	kg/MMBtu		0.45273973
Fuel HHV Correction Factor	**0.962**				CH_4=	0.003	kg/MMBtu	CH_4=	0.001	kg/MMBtu		

Heater Emission Calculations

Pollutants														
PM	7.6 Lb / MMScf (EPA)	×	0.500 MMBtu / Hr	×	Scf (EPA) / 981 Btu	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb	×	0.962	=	**0.016 Tons / Year**	
SO_2	0.60 Lb / MMScf (EPA)	×	0.500 MMBtu / Hr	×	Scf (EPA) / 981 Btu	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb	×	0.962	=	**0.001 Tons / Year**	
NO_X	100 Lb / MMScf (EPA)	×	0.500 MMBtu / Hr	×	Scf (EPA) / 981 Btu	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb	×	0.962	=	**0.215 Tons / Year**	
CO	84 Lb / MMScf (EPA)	×	0.500 MMBtu / Hr	×	Scf (EPA) / 981 Btu	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb	×	0.962	=	**0.180 Tons / Year**	
VOC	5.5 Lb / MMScf (EPA)	×	0.500 MMBtu / Hr	×	Scf (EPA) / 981 Btu	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb	×	0.962	=	**0.012 Tons / Year**	
HAP	1.89 Lb / MMScf (EPA)	×	0.500 MMBtu / Hr	×	Scf (EPA) / 981 Btu	×	8,760 Hr / Year	×	1 Ton / 2,000 Lb	×	0.962	=	**0.004 Tons / Year**	
CO_2	0.5 MMBtu / Hr	×	53.02 kg / MMBtu	×	0.001 Metric Ton / kg	×	8,760 Hr / Year	×	1.1023 Tons / 1 Metric Ton			=	**255.98 Tons / Year**	
N_2O	0.5 MMBtu / Hr	×	0.0001 kg / MMBtu	×	0.001 Metric Ton / kg	×	8,760 Hr / Year	×	1.1023 Tons / 1 Metric Ton			=	**0.00048 Tons / Year**	
CH_4	0.5 MMBtu / Hr	×	0.001 kg / MMBtu	×	0.001 Metric Ton / kg	×	8,760 Hr / Year	×	1.1023 Tons / 1 Metric Ton			=	**0.00483 Tons / Year**	
Mass Sum	255.98 Tons / Year **CO_2**	+	0.0005 Tons / Year **N_2O**	+					0.0048 Tons / Year **CH_4**			=	**255.99 Tons / Year**	
CO_2e	255.98 TPY **CO_2**	× 1		+	0.0005 TPY **N_2O**	× 298		+	0.0048 TPY **CH_4**	× 25		=	**256.25 Tons / Year**	
	255.98			+	0.14			+	0.12					

[1] AP-42 emission factors taken from Chapter 1.4. Based on natural gas with 1020 btu/scf, and corrected in calculations. From Chapter 1.5, propane emission factors are equivalent on a heat basis to methane factors, except the NO_X factor is 1.5x higher.

ATTACHMENT B: DRAFT PROVISOS