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AFS Plant I.D. Number:	16-005-00049

Statement of Basis

Title V Air Quality Operating Permit
Permit Renewal #2

Permit Writer: Christopher Familiare

Williams Corporation, Northwest Pipeline LLC
Pocatello Compressor Station

Fort Hall Indian Reservation
Pocatello, Idaho

Purpose of Permit and Statement of Basis

Title 40 Code of Federal Regulations Part 71 establishes a comprehensive air quality operating permit program under the authority of Title V of the 1990 amendments to the federal Clean Air Act. The air quality operating permit is an enforceable compilation of all of the applicable air pollution requirements that apply to an existing affected air emissions source. The permit is developed via a public process, may contain additional new requirements to improve monitoring of existing requirements, and contains procedural and prohibitory requirements related to the permit program itself. The permit is valid for five years and may be renewed.

This document, the statement of basis, summarizes the legal and factual basis for the permit conditions in the air quality operating permit to be issued to Northwest Pipeline for their Pocatello Compressor Station (referred to herein as facility, source, or permittee). Unlike the air quality operating permit, this document is not legally enforceable. This statement of basis summarizes the emitting processes at the facility, air emissions, permitting and compliance history, the statutory or regulatory provisions that relate to the subject facility, and the steps taken to provide opportunities for public review of the permit. The permittee is obligated to follow the terms of the permit. Any errors or omissions in the summaries provided here do not excuse the permittee from the requirements of the permit.

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Abbreviations & Symbols

#	Number
%	Percent
Btu	British thermal units
BBL	Barrels (42 gallons)
CAA	Clean Air Act [42 U.S.C. section 7401 et seq.]
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	Carbon monoxide
COMS	Continuous opacity monitoring system
EPA	United States Environmental Protection Agency (also U.S. EPA)
EU	Emission Unit
FARR	Federal Air Rules for Reservations
FR	Federal Register
gr/dscf	Grains per dry standard cubic foot
gr	grains (7,000 grains = 1 pound)
HAP	Hazardous Air Pollutant
Hr	Hour
IEU	Insignificant Emission Unit
IC	Internal combustion
lb	Pound (lbs = pounds)
MACT	Maximum Achievable Control Technology
MMBtu	One million Btu
NESHAP	National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)
No.	Number
NO_x	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	Oxygen
PM	Particulate matter
PM_{10}	Particulate matter less than or equal to 10 microns in aerodynamic diameter
$PM_{2.5}$	Particulate matter less than or equal to 2.5 microns in aerodynamic diameter
ppmv	Parts per million on a volume basis
PSD	Prevention of Significant Deterioration
PTE	Potential to emit (based on 8,760 hours of operation per year)
RICE	Reciprocating internal combustion engines
S	Sulfur
scf	Standard cubic feet (for natural gas is at 1 atmosphere and 60 degrees F)
SO_2	Sulfur dioxide
tpy	Tons per year
VOC	Volatile organic compound

1. EPA Authority to Issue Title V Permits

On July 1, 1996, EPA adopted regulations (see 61 Federal Register (FR) 34202) codified at 40 Code of Federal Regulations (CFR) Part 71 setting forth the procedures and terms under which the Agency would administer a federal operating permit program. These regulations were updated on February 19, 1999 (64 FR 8247) to incorporate EPA's approach for issuing federal operating permits to affected stationary sources in Indian Country, and have been updated since from time to time.

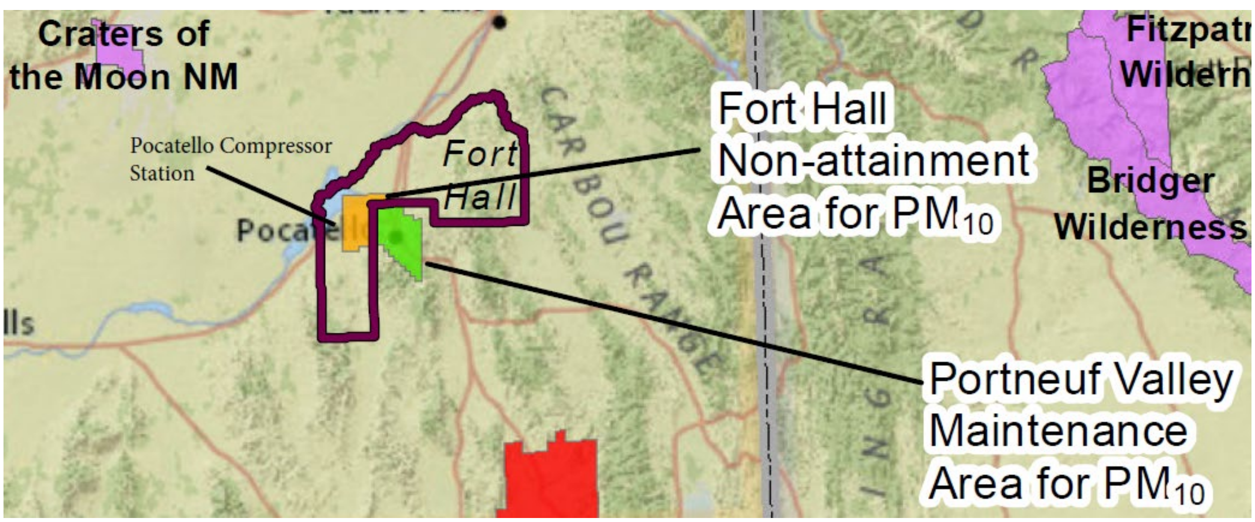
As described in 40 CFR 71.4(b), EPA will implement and enforce a part 71 operating permit program in Indian country when an operating permit program which meets the requirements of part 70 has not been granted approval by the Administrator. Unlike States, Indian Tribes are not required to develop operating permit programs, though EPA encourages Tribes to do so. See, for example, Indian Tribes: Air Quality Planning and Management (63 FR 7253, February 12, 1998) (also known as the “Tribal Authority Rule”). EPA may delegate the authority to administer a part 71 operating permit program, in whole or in part, to an Indian Tribe as described in 40 CFR 71.4(j) and 71.10.

2. Facility Information

2.1 Location

The Northwest Pipeline Pocatello Compressor Station is a privately-owned facility located at 2605 Gas Plant Road in Power County, Idaho. It is approximately 12 miles west of the City of Pocatello, and 19 miles southeast of the town of Fort Hall. The facility is located within the boundaries of the Fort Hall Indian Reservation and is in Indian Country, as defined by 40 CFR Part 71. A map of the local area surrounding the facility is presented in Figure 2-1 with the Fort Hall Indian Reservation outlined in burgundy, the Fort Hall PM_{10} non-attainment area highlighted in yellow and the Portneuf Valley PM_{10} maintenance area highlighted in green.

Figure 2-1 – Facility Location



Map produced by Idaho Department of Environmental Quality

2.2 Fort Hall Indian Reservation

The Northwest Pipeline Pocatello Compressor Station is located on the Fort Hall Indian Reservation in south east Idaho. The Fort Hall Indian Reservation was established by the Bridger Treaty of 1868 as a 1,350 square mile reservation for the Shoshone and Bannock Tribes. The current size of the reservation is 849.8 square miles (543,900 acres). The total population residing on the Fort Hall Reservation is below 10,000. The map in Figure 2-1 above shows the location of the Northwest Pipeline Pocatello Compressor

Station relative to its position within the Fort Hall Reservation.

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2.3 Local Air Quality and Attainment Status

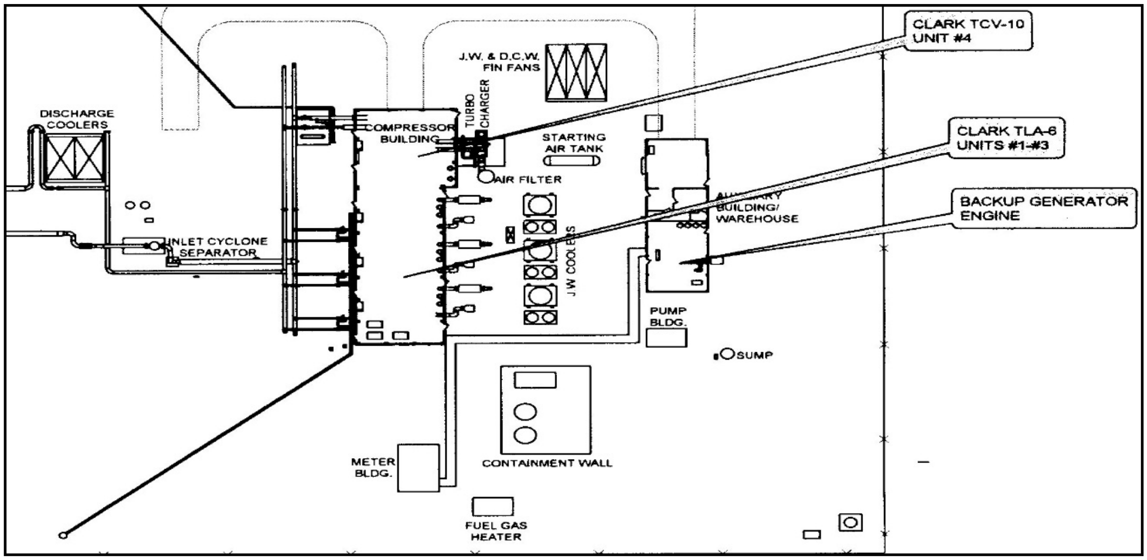
The EPA sets National Ambient Air Quality Standards for criteria air pollutants and then determines whether areas in the country meet the standards. Areas that fail to meet national standards are called nonattainment areas. Areas that meet national standards are called attainment areas (designated "unclassifiable/attainment"). In some cases, the EPA is not able to determine an area's status after evaluating the available information. Those areas are designated "unclassifiable." The Fort Hall Indian Reservation and surrounding area has been designated unclassifiable/attainment for the $PM_{2.5}$, ozone, CO, NO_2 and SO_2 standards. As designated under 40 CFR 81.313 a PM_{10} nonattainment area lies within a portion of the Fort Hall Indian Reservation. The compressor station lies about two miles west of the nonattainment area (see Figure 2-1 above).

The closest Class I designated area to the compressor station is the Craters of the Moon National Monument (see figure 2-1 above) which is located approximately 52 miles northwest of the Pocatello Compressor Station. The Craters of the Moon National Monument is listed in 40 CFR 81.410 as a Class I area for the purpose of major new source review (PSD) impact evaluation.

2.4 Facility Description

Northwest Pipeline Corporation is a subsidiary of Williams Gas Pipeline Company, LLC. Northwest Pipeline Corporation owns and operates Williams' westernmost natural gas pipeline. The pipeline extends from Washington State to New Mexico, passing through Oregon, Idaho, Wyoming, and Colorado. The pipeline serves commercial, industrial and utility natural gas customers. The Pocatello Compressor Station is one of many compressor stations located along the pipeline that assist in the transport of natural gas through the pipeline. The compressor station fits under the standard industrial classification (SIC) code 4922 for natural gas transmission. A plot plan of the facility is shown in Figure 2-2 below.

Figure 2-2 – Northwest Pipeline Pocatello Compressor Station Plot Plan



The air pollution emission units located at the facility are listed in Table 2-1 below. None of the emission units at the Pocatello Compressor Station employ add-on emission control devices. Each of the combustion units vent directly to the atmosphere through an individual stack, except for furnaces and space heaters that generate emissions inside buildings. Installation dates for each emissions unit are listed because they are important in determining applicability of federal NSPS and MACT standards (see further discussion in Section 4).

An emission unit or activity qualifies as an insignificant emission unit (IEU) if it is an activity type listed in 40 CFR 71.5(c)(11)(i) or emits less than 2 tons per year of any regulated air pollutant excluding HAPs [40 CFR 71.5(c)(11)(ii)(A)] and less than 1000 pounds per year of any HAP or the de minimis HAP level established under Section 112(g), whichever is lower [40 CFR 71.5(c)(11)(ii)(B)]. IEUs that are listed activity types need not be included in permit applications and fee calculations as long as the permit application does not omit information needed to determine the applicability of, or to impose, any applicable requirements. IEUs that qualify because they meet the insignificant emission levels (thresholds) only need to be listed in permit applications (and again as long as the application does not omit information needed for applicability), but cannot be excluded from fee calculations. IEUs are in no way exempt from applicable requirements, or any other requirement of the Title V permit.

Northwest Pipeline claimed three oil storage tanks (EU11) as IEUs on EPA Form IE in their Title V application. Northwest Pipeline also noted that natural gas-fired space heaters (Unit #8) and the natural gas pipeline and fuel system (Units #9 & 10) are IEUs. The emission units are not listed IEU activity types, but the potential to emit for each of the emission units is below the IEU thresholds. Because all of the IEUs qualify by meeting the IEU thresholds, their emissions must be included in fee calculations; as such, these emission units have been included in the emission inventory in Appendix A.

2.5 Identification of Emission Generating Activities

The air pollution emission units and control devices that exist at Northwest Pipeline are listed in Tables 2-1 below by emission unit identification (EU ID) and categorized as either generating fugitive or non-fugitive emissions. Installation dates (if known) for each emission unit are listed because they are important in determining applicability of federal PSD, NSPS and MACT standards (see further discussion in Section 4). Capacities are listed for several emission units based on the best information available from the applicant. Those control devices that are required by rule or this permit are so noted.

Table 2-1: Emission Units (EU) & Control Devices

EU ID #	Emission Unit Description	Control Device
Unit 1	Clark TLA-6 Gas Compressor Engine; Two-stroke, lean-burn, reciprocating IC engine; natural gas fired, 14.8 MMBtu/hr, 2,000 horsepower; SN: 73546, installed 1956	None
Unit 2	Clark TLA-6 Gas Compressor Engine; Two-stroke, lean-burn, reciprocating IC engine; natural gas-fired, 14.8 MMBtu/hr, 2,000 horsepower; SN: 73547, installed 1956	None
Unit 3	Clark TLA-6 Gas Compressor Engine; Two-stroke, lean-burn, reciprocating IC engine; natural gas fired, 14.8 MMBtu/hr, 2,000 horsepower; SN: 73548, installed 1956	None
Unit 4	Clark TCV-10 Gas Compressor Engine; Two-stroke, lean-burn, reciprocating IC engine; natural gas fired; 21.7 MMBtu/hr, 4,300 horsepower; SN: 107027, installed 1956	None
Unit 5	Caterpillar 3408 Emergency Generator Engine; Four-stoke, rich-burn, reciprocating IC engine; natural gas fired, 3.76 MMBtu/hr natural gas fired, 400 horsepower; SN: CA 00844, installed 1998	None
Unit 6	Sellers Boiler; Model C80W; natural gas fired, 3.35 MMBtu/hr; Provides glycol heat to keep compressor engines on warm standby, installed 1989	None
Unit 7	Sivallis Fuel Gas Heater; Model SB16-16; natural gas fired, 0.5 MMBtu/hr natural gas fired; Pre-heats fuel for compressor engines and the Sellers boiler, installed 2000	None
Unit 8*	Miscellaneous non-fugitive activities (MNFA) consist of furnaces and space heaters that generate emissions inside buildings.	None
Unit 9*	System Blowdown Gas: Once per year where the source conducts an Emergency Shutdown Test where the source is isolated from the natural gas line and the system is purged venting natural gas to the atmosphere. Approximately 350,000 cubic feet of natural gas is vented during this MNFA Emergency Shutdown Test.	None
Unit 10*	Miscellaneous fugitive activities (MFA) consist of leaks from the piping valves, flanges, and open-ended lines, and compressors associated with the source.	None
Unit 11*	Used Oil Tank, 2,940 gallons (70 BBL); Used Lube Oil Tank, 11,760 gallons (280 BBL); Scrubber Oil Tank, 1,250 gallons (29.8 BBL) - Scrubber tank stores oil that is removed (knockout) from the natural gas prior to compression.	None

* Insignificant Emission Units (IEU). See the Statement of Basis Section 2.4 for more information.

An emission unit or activity qualifies as an IEU if it is an activity type listed in 40 CFR 71.5(c)(11)(i) or emits less than two tons per year of any regulated air pollutant excluding HAPs [40 CFR 71.5(c)(11)(ii)(A)] and less than 1,000 pounds per year of any HAP or the de minimis HAP level established under Section 112(g), whichever is lower [40 CFR 71.5(c)(11)(ii)(B)]. The IEUs listed in Table 2-1 above have been identified by Northwest Pipeline as IEUs on the basis that each unit's potential to emit (PTE) for any individual regulated air pollutant (excluding HAPs) does not exceed two tons per year.

2.6 Permitting, Construction and Compliance History

The Pocatello Compressor Station was originally constructed in 1956 with the installation of three 2,000 hp Clark TLA-6 gas compressor engines. In 1969 a 4,300 hp Clark TCV-10 gas compressor engine was installed at the site to increase the facility's compressor capacity. All four compressor engines are still in use today. In 1998, an emergency backup generator was installed to ensure electrical reliability at the site. Northwest Pipeline has not applied for, or received any new source review permits for the construction or installation of equipment at the facility. Northwest Pipeline indicates that there have been no modifications, or installations, of any large emission unit(s), after major new source review (PSD permitting) requirements went into effect. EPA has not drawn any conclusions regarding compliance with PSD permitting requirements, and no enforcement shield is implied or granted.

Either the EPA, or the Shoshone-Bannock Tribes Air Quality Program on behalf of EPA, have inspected the Pocatello Compressor Station at least every other year since issuance of the initial Title V permit in October 2002. The associated inspection reports indicate that the source has been operating in compliance with applicable air pollution requirements.

A chronologic summary of Title V permit activities for the Pocatello Compressor Station is provided below.

October 17, 2002	EPA issues initial Title V permit with an effective date of December 2, 2002. This is a five-year renewable permit with an expiration date of December 2, 2007. The renewal application was due on June 2, 2007, six months prior to permit expiration.
June 3, 2005	EPA issues letter to Northwest Pipeline requiring the Title V application be updated to include Federal Air Regulations for Reservations (FARR).
June 1, 2007	EPA receives Title V permit renewal application from Northwest Pipeline.
June 13, 2007	EPA receives additional information for the application regarding applicable regulations, including FARR requirements.
July 6, 2007	EPA receives additional information for the application regarding the designation of responsible officials.
October 29, 2007	Meeting with Northwest Pipeline at EPA Region 10 to review permit renewal process and expectations. EPA requested additional information.
December 5, 2007	EPA receives additional information for the application including emission factors, list of IEUs, plot plan and photographs of the facility.
July 30, 2015	EPA receives additional information for the application including applicable requirements under 40 CFR Part 63 to the boiler and process heater.
August 29, 2015	Public comment period for draft permit and statement of basis begins
September 28, 2015	Public comment period for draft permit ends.
September 30, 2015	Final permit issued with an effective date of October 31, 2015. Expiration date September 30, 2020.
September 9, 2019	EPA receives Title V permit renewal application from Northwest Pipeline.
November 13, 2019	EPA receives additional information regarding NSPS Subparts A/JJJJ reconstruction/modification applicability for the facility's four engines.

March 10, 2020	Public comment period for draft permit and statement of basis begins.
April 13, 2020	Public comment period for draft permit ends.
May 18, 2020	Final permit issued with an effective date of May 18, 2020. Expiration date May 18, 2025.

3. Emission Inventory

3.1 Emission Inventory Basics

An emission inventory generally reflects either the "actual" or "potential" emissions from a source. Actual emissions generally represent a specific period of time and are based on actual operation and controls. Potential emissions, referred to as potential to emit (PTE), generally represent the maximum capacity of a source to emit a pollutant under its physical and operational design, taking into consideration regulatory restrictions, but only required control devices. PTE is often used to determine applicability to several EPA programs, including Title V, PSD and Section 112 (MACT).

Emissions can be broken into two categories: point and fugitive. Fugitive emissions are those which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Examples of fugitive emissions are roads, piles that are not normally enclosed, wind blown dust from open areas, and those activities that are normally performed outside buildings. Point sources of emissions include any emissions that are not fugitive.

The equation below represents the general technique for estimating emissions (in tons per year) from each emission unit at the facility. Emissions are calculated by multiplying an emission factor by an operational parameter. To estimate actual emission, the permittee will need to track the actual operational rates. Note that emission factors may be improved over time. For those estimation techniques that require substantial site-specific parameter tracking, such as piles and roads, emissions associated with a defined operational rate can be estimated to establish a set ratio that can be used to multiply by the actual operational rate in future years, significantly simplifying the annual inventory effort. All of the techniques and site-specific parameters and assumptions should be reviewed each year before estimating emissions to be sure they remain appropriate.

$$E = EF \times OP \times K$$

Where:

E = pollutant emissions in tons/year

EF = emission factor (see Appendix A to this Statement of Basis)

OP = operational rate (or capacity for PTE)

K = 1 ton/2000 lbs for conversion from pounds per year to tons per year

3.2 Potential to Emit (PTE)

Northwest Pipeline submitted emission inventories of actual and potential emissions for the Pocatello Compressor Station with its Title V permit renewal application. EPA reviewed Northwest Pipeline's inventory and has documented the facility PTE in Appendix A. The PTE estimates for the compressor station assumes all units operate 8760 hours per year and no enforceable emission controls exist that limit emissions with the exception of the emergency backup electrical power generator which assumes no more than 500 hours of operation. A summary of Northwest Pipeline's non-fugitive PTE (except for HAPs) is presented in Table 3-1 below. Note that fugitive emissions are not included for non-HAP emissions, because for compressor stations fugitive emissions are not used to determine program applicability as explained in more detail in Section 4.1 of this Statement of Basis. HAPs are used to determine applicability for MACT purposes.

Table 3-1 – Pocatello Compressor Station Potential to Emit (tpy)[1]

Pollutant[2]	Emission Units						Total
	Four Natural Gas Compressor RICE	Backup Generator RICE	Boiler & Heater	Heaters & Furnaces	System Blowdown	Equipment Leaks & Oil Storage Tanks	
CO	100.2	3.5	1.4	0.4			106
NO_X	1087.6	2.1	1.7	0.5			1,092
PM	11.1						11
PM_{10}	13.8		0.1				14
$PM_{2.5}$	13.8		0.1				14
SO_2	15.8	0.1	1.0	0.3			17
VOC	32.4		0.1		0.2		33
GHG (CO_2e)	33,924	110	2,059	605	178		36,876
Facility-wide Single HAP							16.0
Facility-wide Total HAP							23.2

[1] Fugitive emissions are not included in this table (except for HAPs) because fugitives are not used in applicability determinations for this source type (see Section 4.1). For fugitive emission estimates, see Appendix A.
[2] CO = carbon monoxide; NO_X = oxides of nitrogen; PM = particulate matter; PM_{10} = inhalable coarse particulate or particulate matter with diameter 10 microns or less; $PM_{2.5}$ = fine particulate or particulate matter with diameter 2.5 microns or less; SO_2 = sulfur dioxide; VOC = volatile organic compounds; GHG = greenhouse gases; CO_{2e} = carbon dioxide equivalent; HAP = hazardous air pollutants [see CAA, Section 112(b)]; facility-wide total HAP = all HAPs totaled; facility-wide single HAP = highest individual HAP.

Northwest Pipeline is expected to use the emission factors and calculation methods listed in Appendix A unless Northwest Pipeline demonstrates that a more appropriate emission factor or calculation method should be used (e.g., results of more recent source testing or sampling, revised emission factors published in AP-42 or etc.). It is important to emphasize that to the extent Northwest Pipeline relies on any type of emission control technique to estimate emissions used to determine annual fees, or the applicability of a regulatory program, use of the technique must be fully documented and verifiable.

3.3 Actual Emissions

Northwest Pipeline is required to pay fees annually based on an inventory of its actual emissions for the preceding calendar year (see Permit Conditions 3.41 through 3.45). Table 3-3 summarizes Northwest Pipeline's reported actual emissions generated in calendar year 2018.[1]

[1] Although Northwest Pipeline is not required to report CO emissions for the purpose of part 71 fee payment, CO emissions were reported as required by the Federal Air Rules for Reservations (FARR). See 40 CFR 49.138(f) and 71.2. Greenhouse gas emissions were not reported as GHG is not classified as a "regulated pollutant (for fee calculation)" and GHG is not a pollutant for which the FARR registration program requires annual reporting of emissions. See 40 CFR 49.138(e)(3)(xii) and 71.2. PM emissions were not reported as PM is not a regulated pollutant in the context of the part 71 program and PM is not a pollutant for which the FARR registration program requires annual reporting of emissions. See 40 CFR 49.138(e)(3)(xii) and October 16, 1995 EPA memorandum entitled, "Definition of Regulated Pollutant for Particulate Matter for Purposes of Title V." $PM_{2.5}$ emissions were not reported as they were assumed to be equivalent to PM_{10} emissions.

Table 3-2: Pocatello Compressor Station Actual Emissions (tons) for Calendar Year 2018

Pollutant	Emission Units					Total
	Four Natural Gas Compressor RICE	Backup Generator RICE, Boiler & Heater	Heaters & Furnaces	System Blowdown	Equipment Leaks & Oil Storage Tanks	
CO	47.02	0.91	No emissions reported for fee purposes as these emission units are IEU's. See 40 CFR 71.9(c)(5)(iii).			47.9
NO_X	395.17	1.07				396.2
PM_{10}	4.05	0.08				4.1
SO_2	0.69	0.01				0.7
VOC	9.56	0.06				9.6
Formaldehyde (highest-emitting HAP)	4.63	0.02				4.7

4. Regulatory Analysis

The EPA is required by 40 CFR part 71 to include in this Title V permit all emission limitations and standards that apply to the facility, including operational, monitoring, testing, recordkeeping and reporting requirements necessary to assure compliance. This section explains which air quality regulations apply to this facility and how those requirements are addressed in the permit.

Located in Indian Country, the Pocatello Compressor Station is subject to federal air quality regulations, and is not subject to state air quality regulations. The EPA does not consider permits issued by Idaho to the Pocatello Compressor Station to be applicable requirements. The facility could be subject to tribal air quality regulations; however, the Shoshone-Bannock Tribes has not gone through the process of obtaining authorization to be treated in the same manner as states under 40 CFR 49.6 and 49.7 (Tribal Authority Rule) and obtaining approval of air quality regulations as a "Tribal Implementation Plan." Therefore, Tribal air quality regulations, if any, are not federally enforceable and do not meet the definition of "applicable requirement" under 40 CFR part 71. As such, there are no Tribal air quality regulations included in the Pocatello Compressor Station Title V permit.

The EPA relied on information provided in Northwest Pipeline's Title V permit application and on supplementary information provided by Northwest Pipeline to determine the requirements that are applicable to the Pocatello Compressor Station. Future modifications to the facility could result in additional requirements.

4.1 Federal Air Quality Requirements

Title V Operating Permit Program. Title V of the CAA and the implementing regulation found in 40 CFR part 71 require major sources (as well as specified non-major sources) of air pollution to obtain operating permits and form the legal bases for this permit. A source is major if it has the potential to emit 100 tons per year or more of any air pollutant subject to regulation, 25 tons per year or more of hazardous air pollutants (totaled) or 10 tons per year or more of any single hazardous air pollutant (see 40 CFR 71.2). The Pocatello Compressor Station is a major source subject to Title V because it has the potential to emit more than 100 tons per year of NO_X and CO and more than 10 tons per year of the HAP formaldehyde (see Table 3-1 and Appendix A).

The Title V operating permit serves as a comprehensive compilation of the air quality requirements that are applicable to a source. The permit also must assure compliance, so source-specific testing, monitoring, recordkeeping and reporting have been added where necessary, as explained in Section 5 (Permit Content) of this Statement of Basis below.

New Source Review. The New Source Review (NSR) program requires stationary source owners or operators to obtain a permit before they begin construction of a new source or a modification to an existing source. In other words, facilities are required to obtain NSR permits for the construction of entirely new facilities and for construction projects at existing facilities such as expansions, additions, process changes, and equipment modifications. By requiring sources to meet pre-construction requirements, the NSR program provides a mechanism to improve the air quality in nonattainment areas and to maintain the air quality in attainment areas.

There are three types of NSR permitting programs, each with a different set of requirements. A facility may be required to meet one or more of these sets of permitting requirements when the facility undertakes a modification. The Prevention of Significant Deterioration (PSD) program applies to the construction of a new major source or a major source making a major modification that is located in an attainment area. The PSD program generally applies to facilities that have the potential to emit 250 tons per year (tpy) or 100 tpy or more of any regulated NSR pollutant. The thresholds depend on the type of source and there is a list of 28 source categories for which the 100 tpy threshold applies. The Nonattainment NSR (NA NSR) program applies to the construction of a new major source or a major source making a major modification that is located in a nonattainment area. Generally, the NA NSR program applies to facilities that have the potential to emit 100 tpy or more of a NAAQS pollutant. However, this threshold can be lower depending on the nonattainment severity of the area where the source is or will locate. The Minor NSR program applies to a new minor source and/or a minor modification at both major and minor sources, in both attainment and nonattainment areas. Minor NSR will apply for those regulated NSR pollutants that are emitted at or above the minor NSR thresholds specified in the Tribal minor NSR rule (Table 1 to 40 CFR 49.153) but below the major source thresholds.

Because the area in which the Pocatello Compressor Station is located is not classified non-attainment for any pollutant, the NA NSR program is not currently relevant. Based upon our knowledge of the facility and understanding of its potential emissions, the Pocatello Compressor Station is a PSD major source. It has been a major source since the beginning of the PSD program. A modification to an existing major source is subject to PSD review for each pollutant experiencing an emissions increase greater than defined PSD significance level. A modification to an existing major source is subject to minor NSR for each pollutant experiencing an emissions increase greater than the defined minor NSR significance level but less than the defined PSD significance level. Whereas the minor NSR program became effective August 30, 2011, the first version of the PSD program became effective in the late 1970's. The four main gas compressor engines (Emission Units 1, 2, 3 and 4) were installed before the late 1970's. The backup engine (Emission Unit 5), added to the facility in 1998, resulted in a potential increase of 36 tons per year of NO_X and 61 tons per year of CO.[2] The thresholds for a significant increase are 40 and 100 tons per year for NO_X and CO, respectively, so the addition of the backup engine was not a major modification subject to PSD review. The addition of the backup was not a modification subject minor NSR because that permit program did not exist in 1998.

New Source Performance Standards (NSPS). There are no NSPS regulations applicable to the Pocatello Compressor Station. The following is a list of four potentially applicable NSPS regulations and explains why each is not applicable to the facility.

40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.

[2] The EPA September 6, 1995 guidance document entitled, "Calculating PTE for Emergency Generators," and its statement that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions, the construction of Unit #5 resulted in a potential increase of 2.1 tpy NO_X and 3.5 tpy CO. See Appendix A to this Statement of Basis for the calculation of these values.

NSPS Subpart Kb applies to storage vessels with a capacity greater than or equal to 75 cubic meters (m^3) (19,800 gal) used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

Conclusion: The largest storage tank at the Pocatello Compressor Station is 280 barrels (bbl) (11,760 gal) of lubrication oil. This volume is less than the NSPS Subpart Kb requirement, and the facility commenced operation prior to July 23, 1984; therefore, Subpart Kb does not apply. Construction of the newest storage tank (scrubber oil tank) commenced after July 23, 1984, but its 1,250-gallon capacity is less than the 19,800-gallon applicability threshold. Subpart Kb does not apply to the newest tank.

40 CFR Part 60 Subpart KKK – Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants

NSPS Subpart KKK applies to equipment leak components at onshore natural gas processing plants that commenced construction after January 20, 1984. A natural gas processing plant is defined in Subpart KKK as any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both [40 CFR 60.631].

Conclusion: Pocatello Compressor Station is a natural compressor station and it does not extract or fractionate natural gas liquids. Operation commenced prior to January 20, 1984; therefore, Subpart KKK does not apply.

40 CFR Part 60 Subpart LLL – Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions

NSPS Subpart LLL applies to facilities the following facilities that process natural gas: each sweetening unit and each sweetening unit followed by a sulfur recovery unit.

Conclusion: The Pocatello Compressor Station does not operate natural gas sweetening units or sulfur recovery units; therefore, Subpart LLL does not apply.

40 CFR Part 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

NSPS Subpart JJJJ applies to stationary spark ignition internal combustion engines that commence construction after June 12, 2006, where the engines are manufactured:

- On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);
- On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;
- On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or
- On or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

Conclusion: Each of the stationary spark ignition internal combustion engines at the Pocatello Compressor Station commenced construction prior to June 12, 2006; therefore, they are considered existing and therefore not subject to the requirements of Subpart JJJJ [40 CFR 60.4230(a)(4)].

National Emission Standards for Hazardous Air Pollutants (NESHAP). With a few exceptions, NESHAP standards promulgated under 40 CFR part 63 apply to "major sources" of HAP. Section 112(a)(1) and 40 CFR 63.2 define a "major source" as a 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 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP. The Northwest Pipeline Pocatello Compressor Station is a major source of HAP as it emits approximately 16 tons of formaldehyde. See PTE emissions inventory in Appendix A.

The following is a list of two potentially applicable NESHAP regulations and explains why each is not applicable to the facility.

<u>40 CFR Part 63 Subpart HH – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities</u>

NESHAP Subpart HH applies to oil and natural gas production facilities that are major and area sources of HAPs. A major source is defined as a stationary source that emits or has the potential to emit 10 tpy of any single HAP or 25 tpy of total HAPs, and an area source is any stationary source of HAPs that is not a major source [40 CFR 63.2].

For facilities that are major HAP sources, this subpart applies to facilities that process, upgrade or store hydrocarbon liquids prior to the point of custody transfer or facilities that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user.

The affected sources for major sources of HAPs include the following:

- Each glycol dehydration unit;
- Each storage vessel with the potential for flash emissions;
- Compressors or ancillary equipment operating in volatile hazardous air pollutant service located at natural gas processing plants;

The affected sources for area sources of HAPs include the following:

- Each triethylene glycol (TEG) dehydration unit located at an oil and natural gas production facility.

Conclusion: The Pocatello Compressor Station is a natural gas transmission compressor station and is a major source of HAPs. The facility does not meet the NESHAP definition of a natural gas production facility, there are no glycol dehydration units and there are no ancillary equipment operating in volatile HAP service, therefore, Subpart HH does not apply.

<u>40 CFR Part 63 Subpart HHH – National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities</u>

NESHAP Subpart HHH applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of HAP emissions. The applicable affected source is each glycol dehydration unit. An owner or operator of a facility that does not contain a glycol dehydration unit is not subject to the requirements of this subpart.

Conclusion: The Pocatello Compressor Station is a natural gas transmission compressor station and is a major source of HAPs, however, the facility does not operate a glycol dehydration unit, therefore, Subpart HHH does not apply [40 CFR 63.1270(a), (b) & (c)].

<u>40 CFR Part 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines</u>

There are two NESHAP standards that are applicable to this facility: Subpart ZZZZ (Stationary Reciprocating Internal Combustion Engines (RICE)) and Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters at Major Sources). Subpart ZZZZ applies to the Emergency Backup Electrical Power Generator (Unit #5) and Subpart DDDDD applies to the boiler and fuel gas heater (Units #6 and 7). The applicable requirements in Subparts ZZZZ and DDDDD have been incorporated into Sections 5 and 6 of the permit, respectively.

Any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand is subject to 40 CFR 63

Subpart ZZZZ. There are five stationary RICE at the Pocatello Compressor Station. In accordance with 40 CFR 63.6590(a), these engines are affected sources under 40 CFR Part 63, subpart ZZZZ. However, in accordance with 40 CFR 63.6590(b)(3)(i), four of these engines (Units 1, 2, 3, and 4) do not have to meet the requirements of 40 CFR Part 63, subpart ZZZZ or subpart A, including the initial notification requirements. Table 4-1 below summaries MACT ZZZZ applicability.

Table 4-1 – MACT Subpart ZZZZ Applicability for IC Engines

EU I.D. #	Description	Fuel	Capacity	Subpart ZZZZ Applicable?
1, 2 and 3	Clark TLA-6 Gas Compressor Engine; Two-stroke, lean-burn; Installed 1956	Natural gas	14.8 MMBtu/hr 2,000 horsepower	Yes, under the category of existing, two-stroke, lean-burn engine
4	Clark TCV-10 Gas Compressor Engine; Two-stroke, lean-burn; Installed 1969	Natural gas	21.7 MMBtu/hr 3,400 horsepower	Yes, under the category of existing, two-stroke, lean-burn engine
5	Caterpillar 3408 Emergency Backup Generator Engine; Four-stoke, rich-burn; Installed 1998	Natural gas	3.76 MMBtu/hr 400 horsepower	Yes, emergency stationary RICE.

The Caterpillar emergency backup electrical generator (Unit #5) is an affected source under Subpart ZZZZ because it is an emergency stationary RICE under 40 CFR 63.6585(f). Under 40 CFR 63.6585(f), an emergency stationary RICE must meet the definition of such a RICE under 40 CFR 63.6675, which includes operating according to the provisions specified in 40 CFR 63.6640(f).

Each of the compressor engines at the facility are rated at greater than 500 horsepower, and therefore are regulated engines under the rule. However, these engines are considered "existing" engines because they were constructed and installed prior to December 19, 2002. Subpart ZZZZ has distinct requirements for regulated engines depending on their design, use, and fuel. The compressor engines at the Pocatello Compressor Station are categorized as spark-ignition, two-stroke, lean-burn (2SLB) engines under the rule. Existing engines (Units 1, 2, 3, and 4) that are of the spark-ignition, two-stroke, lean-burn design are not subject to any specific requirement under the rule, including being exempt for the initial notification requirements of the NESHAP regulations.

If Northwest Pipeline were to modify any of the compressor engines in a manner that meets the definition of reconstruction under NESHAP regulations, the engine may no longer be considered "existing' under Subpart ZZZZ, and additional requirements from this subpart could apply.

<u>40 CFR Part 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters</u>

Any new, reconstructed, or existing boiler or process heater located at a major source of HAP emissions, excluding any units listed under 40 CFR 63.7491, is subject to 40 CFR 63 Subpart DDDDD. There are two units at the Pocatello Compressor Station that meet the definition of "industrial, commercial, or institutional boiler or process heater," the Sellers boiler and the Sivalls fuel gas line heater. None of the exclusions apply to either of the units. In accordance with 40 CFR 63.7490(a)(1), these two units together are the affected source under 40 CFR Part 63, subpart DDDDD. Table 4-2 below summarizes MACT DDDDD applicability.

Table 4-2 – MACT Subpart DDDDD Applicability for Boiler and Process Heater

EU I.D. #	Description	Fuel	Capacity	Subpart DDDDD Applicable?
6	Sellers C80W Boiler, Glycol Heater; Installed 1989	Natural gas (Gas 1)	3.35 MMBtu/hr	Yes, under the category of existing, boiler
7	Sivalls Fuel Gas Line Heater; Installed 2000	Natural gas (Gas 1)	0.5 MMBtu/hr	Yes, under the category of existing, process heater

According to the applicability criteria in 40 CFR 63.7490(b), (c), & (d), both the Sellers boiler and the Sivalls heater are considered "existing" affected units as construction of each commenced prior to June 4, 2010 and because neither has been reconstructed since that date. Given the type of fuel combusted (Gas 1), neither of these units are subject to either an emissions limitation or operating limit according to 40 CFR 63.7500(e). Which Subpart DDDDD work practice standards apply depends upon the technical specifications of the affected unit. Because each unit has a heat input capacity less than or equal to 5 MMBtu/hr, and because each unit is designed to burn Gas 1, each unit is subject to the requirement to conduct a tune-up every five years pursuant to 40 CFR 63.7500(a)(1), (e) and Item No. 1 of Table 3 to Subpart DDDDD. Because each unit is an existing unit located at a major source (and because neither is a limit use unit), each unit is also subject to a one time-energy assessment pursuant to 40 CFR 63.7500(a)(1) and Item No. 4 of Table 3 to Subpart DDDDD.

Regional Haze Program. The Regional Haze Rule[3] calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas (Class 1 areas) such as the Grand Canyon, Yosemite, the Great Smokies and Shenandoah. The 43,243-acre Craters of the Moon Wilderness Area is the nearest Class 1 area to the facility. The southeast corner of this nearest Class 1 area is approximately 25 miles west of the facility. The area is managed by the United States Department of the Interior's National Park Service.

The Western Regional Air Partnership (WRAP) is a voluntary partnership of states, tribes, federal land managers, local air agencies and EPA whose purpose is to understand current and evolving regional air quality issues in the West. The purpose of the WRAP Regional Haze Planning Work Group (RHPWG)[4] is to prepare the framework to support regional planning for the 15 western states, so that needed elements will be available for Regional Haze state implementation plan (RH SIP) submissions in a timely fashion, to meet the July 2021 deadline for implementation plans to be submitted in each of the 15 states (including Idaho) for the second planning period of the federal Regional Haze Rule for visibility protection at 118 Class I areas. Regional Haze SIPs or FIPs for the second planning period of the Regional Haze Rule are due by July 2021 and may contain additional requirements for sources impacting Class 1 areas.

Section 111(d) and Section 129 Regulations. There are no CAA, Section 111(d) or 129 regulations that apply to the type of emission units at the Northwest Pipeline Pocatello Compressor Station.

Federal Air Rules for Reservations (FARR). On April 8, 2005, EPA promulgated a Federal Implementation Plan (FIP) for Reservations in Idaho, Oregon and Washington, commonly referred to as the Federal Air Rules for Reservations (FARR). The EPA published the FARR rules that generally apply to Indian Reservations in EPA Region 10 in 40 CFR 49.121 to 49.139. The FARR rules that specifically apply on the Fort Hall Reservation (Sections 123, 124, 125, 126, 129, 130, 131, 135, 137, 138 and 139) are codified at 40 CFR 49.10701 to 49.10730. FARR requirements that do not apply to Pocatello Compressor Station are not included in the permit; requirements that apply generally to all subject sources

[3] https://www.govinfo.gov/content/pkg/FR-2017-01-10/pdf/2017-00268.pdf
[4] https://www.wrapair2.org/RHPWG.aspx

but do not create specific requirements for Northwest Pipeline (e.g., applicability provisions, definitions, provisions regarding delegation) are also not included in the permit. The applicable requirements in the FARR have been incorporated into Sections 3 and 4 of the permit.

Compliance Assurance Monitoring. CAM applies at time of initial Title V permit issuance for emission units that (a) are subject to an emission limit, (b) employ a control device to comply with the limit, and (c) have post-control PTE equal to or greater than the major source threshold defined in Title V (generally, 100 tons per year). See 40 CFR 64.5(a). All units that meet the CAM applicability criteria must be in compliance with CAM at initial permit issuance. The initial Title V permit was issued to Northwest Pipeline on October 17, 2002. It was determined at that time that each of the four compressor engines at the Pocatello Compressor Station has a PTE for NO_X greater than 100 tons per year. However, because none of the engines are equipped with a control device, CAM does not apply. That determination continues to remain valid.

Chemical Accident Release Program. Northwest Pipeline has not reported storing a regulated substance above the threshold quantity. The permit contains a placeholder provision requiring the permittee to comply with the chemical accident prevention provisions in 40 CFR part 68 in a timely manner if it becomes subject.

Protection of Stratospheric Ozone. The provisions of 40 CFR part 82, subparts B and F apply to facilities that handle ozone depleting substances (e.g. refrigerants). The permit contains conditions that require the permittee to manage ozone depleting substances and maintain records according to these subparts.

Acid Rain Program. Title IV of the CAA created a SO_2 and NO_X reduction program found in 40 CFR part 72. The program applies to any facility that includes one or more “affected units” that produce electricity. The facility’s boiler is not an “affected unit” as defined in 40 CFR 72.6 because it does not produce electricity.

Mandatory Greenhouse Gas Reporting Rule. This rule requires sources above certain emission thresholds to calculate, monitor, and report greenhouse gas emissions. According to the definition of "applicable requirement" in 40 CFR 71.2, neither 40 CFR part 98, nor CAA 307(d)(1)(V), the CAA authority under which part 98 was promulgated, are listed as applicable requirements for the purpose of Title V permitting. Although the rule is not an applicable requirement under 40 CFR part 71, the source is not relieved from the requirement to comply with the rule separately from compliance with their part 71 operating permit. It is the responsibility of each source to determine applicability to part 98 and to comply, if necessary.

4.2 Other Federal Requirements and Responsibilities

EPA Trust Responsibility. As part of the EPA Region 10’s direct federal implementation and oversight responsibilities, EPA Region 10 has a trust responsibility to each of the 271 federally recognized Indian tribes within the Pacific Northwest and Alaska. The trust responsibility stems from various legal authorities including the U.S. Constitution, Treaties, statutes, executive orders, historical relations with Indian tribes, and in this case the Bridger Treaty of 1868. In general terms, the EPA is charged with considering the interest of tribes in planning and decision making processes. Each office within the EPA is mandated to establish procedures for regular and meaningful consultation and collaboration with Indian tribal governments in the development of EPA decisions that have tribal implications. EPA Region 10’s Air and Radiation Division has contacted the Shoshone-Bannock Tribes to invite consultation on the Northwest Pipeline Pocatello Compressor Station Title V operating permit renewal application.

Endangered Species Act (ESA). Under this act, the EPA is obligated to consider the impact that a federal project may have on listed species or critical habitats. It is the EPA’s conclusion that the issuance of this Title V permit will not affect a listed species or critical habitat because it does not authorize new emissions units, increase existing emission limits or impose any new work practice requirements.

Therefore, no additional analysis and no additional requirements will be added to this permit for ESA reasons. The EPA's no-effect determination concludes the EPA's obligations under Section 7 of the ESA. For more information about EPA's obligations, see the Endangered Species Consultation Handbook: Procedures for Conducting Consultation and Conference Activities under Section 7 of the Endangered Species Act, published by the FWS and NMFS (March 1998, Figure 1).

National Environmental Policy Act (NEPA). Under Section 793(c) of the Energy Supply and Environmental Coordination Act of 1974, no action taken under the CAA shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969. This permit is an action taken under regulations implementing the CAA and is therefore exempt from NEPA.

National Historic Preservation Act (NHPA). As noted earlier, the issuance of this Title V permit does not authorize new emissions units, increase existing emission limits or impose any new work practice requirements. No changes to the facility are expected as a result of this permit action. Consequently, no adverse effects are expected, and further review under NHPA is not indicated.

Environmental Justice (EJ) Policy. Under Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,* signed on February 11, 1994, the EPA is directed, to the greatest extent practicable and permitted by law, to make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States. This permit action does not allow new or additional emissions and therefore impacts. As a result, there is no information available that indicates that there are disproportionately high and adverse impacts to a minority or low-income population.

5. Permit Content

5.1 Permit Conditions for Renewal Permit No. R10T5110200

This Title V operating permit compiles all of the applicable requirements that apply to the permittee. Additional monitoring, recordkeeping and reporting requirements have been created where necessary. In general, each permit condition in the permit is explained below. Certain permit conditions are self-explanatory, and thus are not further discussed. The permit is organized into the following six sections:

Front Page:	Authorization to Operate in Accordance with the Permit
Permit Section 1:	Source Information and Emission Units
Permit Section 2:	Standard Terms and Conditions
Permit Section 3:	General Requirements
Permit Section 4:	Facility-Specific Requirements
Permit Section 5:	Unit-Specific Requirements – NESHAP Subpart ZZZZ for Unit #5 (Emergency Backup Generator)
Permit Section 6:	Unit-Specific Requirements – NESHAP Subpart DDDDD for Units #6 (Boiler) and 7 (Process Heater)

Front Page – Authorization to Operate in Accordance with the Permit

The first page of the permit specifies the relevant statutes within the Clean Air Act and the implementing federal regulations that authorize EPA to issue the permit and allow the permittee to operate and conduct air polluting activities in accordance with the conditions in the permit. The front page also identifies the permittee's contact information as well as the location of the permitted facility.

On January 31, 2020, EPA Region 10 received a request to change the responsible official from Glen

Jasek to Camilo Amezquita. Mr. Amezquita has replaced Mr. Jasek as Vice President and General Manager of Northwest Pipeline LLC. The renewed permit reflects the change.

Permit Section 1 – Source Information and Emission Units

This permit section contains a brief description of the facility and a list of emission units. A more detailed description of the facility can be found in Section 2 of this Statement of Basis. Northwest Pipeline reports one modification to the facility having been undertaken during the five-year term of the current Title V permit. Two 310-gallon (each) scrubber oil tanks have been replaced by one 1,250-gallon scrubber oil tank. The new tank (like the ones it replaced) is recognized as part of Unit #11.

Permit Section 2 – Standard Terms and Conditions

This permit section includes generic compliance terms that are required in all Title V permits, but that Region 10 does not expect to be addressed in the annual compliance certification required in Permit Condition 3.49.

Permit Condition 2.1 explains that the language in the underlying regulations takes precedence over paraphrased language in the permit. Some applicable requirements are paraphrased in the permit with the intention of clarifying the requirement, but with no intention of changing the underlying meaning of the requirement. Where there is a difference between the language in a permit and an underlying regulation, the wording in the underlying regulation governs. This permit condition also notes some underlying authorities that may have been used to create additional requirements in this permit. For instance, Region 10 is relying upon periodic monitoring authority in 40 CFR 71.6(a)(3)(i)(B) to create monitoring requirements when an applicable underlying emission limitation is not accompanied by monitoring. Region 10 is relying upon sufficiency monitoring authority in 40 CFR 71.6(c)(1) to create monitoring requirements when an applicable underlying emission limitation is accompanied by monitoring that we have determined is not sufficient to assure compliance with the limitation.[5]

Permit Conditions 2.4 and 2.5 address a general permit shield which states that compliance with the permit is deemed compliance with the applicable requirements listed in the permit. The permittee is responsible for complying with any applicable requirements that exist but have not been included in the permit. The permittee did not request a specific permit shield for any specific requirement excluded from this permit and none is being granted.

Permit Condition 2.6 incorporates the credible evidence rule as reflected in the various applicable requirements cited as authority for this condition. It makes clear that language in the permit stating "compliance is determined with" or "demonstrate compliance by" does not preclude the use of other credible evidence to demonstrate that the permittee is not in compliance with an applicable requirement.

Permit Conditions 2.7 and 2.8 incorporate the Part 71 provisions regarding permit modification, revocation, reopening, reissuance, and termination for cause.

Permit Conditions 2.9 through 2.11 address the expiration of the permit and the ramifications if the permittee does or does not renew their permit. It is important to note that, if the permittee does not submit a complete and timely renewal application, the permittee's right to operate is terminated. The expiration date of the permit is listed on the top right-hand corner of the front page of the permit. Specific requirements regarding permit renewal are in Permit Conditions 3.51 and 3.52.

Permit Conditions 2.12 through 2.14 address options for making certain physical and operational changes

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[5] In the Matter of Citgo Refining and Chemicals Company L.P., West Plant, Corpus Christi, Texas, Order on Petition No. VI-2007-01 (May 28, 2009). Permitting authorities must incorporate applicable monitoring requirements into the Title V permit, add monitoring when no underlying monitoring exists, and supplement existing monitoring that is not sufficient to assure compliance with permit terms and conditions.

in the facility that do not require a permit modification. If the permittee uses any of these options, they must comply with the applicable recordkeeping requirement found in Permit Condition 3.32 and reporting requirements found in Permit Conditions 3.38 and 3.39.

Permit Section 3 – General Requirements

This permit section includes conditions that are required in all Title V permits. In some cases, facility-specific testing, monitoring, recordkeeping and reporting requirements for these permit conditions are found in Section 4 of the permit because those requirements can vary from permit to permit. Unless otherwise specified, emission units are subject to the general requirements in Section 3 of the permit as well as the facility-specific and unit-specific requirements in Sections 4 through 6.

Permit Conditions 3.1 and 3.2 are general compliance schedule requirements. Because EPA is not aware of any non-compliance at the time of permit issuance, there is no issue-specific compliance schedule in the permit.

Permit Condition 3.3 requires the permittee to allow EPA-authorized representatives access to the facility and required records.

Permit Conditions 3.4 through 3.8 restrict open burning. If the permittee performs any open burning, recordkeeping requirements specific to open burning found in Permit Condition 3.33 will apply.

Permit Conditions 3.9 through 3.11 limit visible emissions, require the use of either RM9 or a continuous opacity monitoring system (COMS) for determining compliance with the limit, and provide exceptions to the rule. RM9 includes specific guidance for reading opacity when there is a wet plume (both attached and detached and directs the observer to take readings excluding the portion of the plume that includes uncombined water (droplets). In the vast majority of cases, the likelihood of exceeding the 20% opacity limit due to the presence of uncombined water is very low because a certified reader would know that he/she should not read that portion of the plume. However, there are meteorological conditions that can prevent uncombined water (droplets) from completely evaporating in a plume (e.g., 100% relative humidity and a saturated plume). The provision in Permit Condition 3.11 addresses that situation.

Because testing, monitoring, recordkeeping and reporting for assuring compliance with the visible emission limit can change based on the emission unit in question, the testing, monitoring, recordkeeping and reporting requirements are contained in facility-specific requirements in Section 4 of the permit, or in each emission unit-specific section, as appropriate. The general monitoring, recordkeeping and reporting for this requirement is the periodic visible emissions survey (plant walkthrough) specified in Permit Conditions 4.7 through 4.13.

Permit Conditions 3.12 through 3.17 restrict fugitive particulate matter emissions and require a plan be created to assure the use of reasonable precautions to prevent fugitive emissions. The plan is based on a survey of the facility and is updated annually. This annual survey can be accomplished simultaneously with the periodic visible emission survey requirement in Permit Conditions 4.7 through 4.13, as long as both requirements are fully complied with.

Permit Condition 3.18 addresses requirements in the Chemical Accident Prevention Program found in 40 CFR part 68. This program requires sources that use or store regulated substances above a certain threshold to develop plans to prevent accidental releases. Based on information in their application, there are no regulated substances above the threshold quantities in this rule at this facility; therefore, the facility is not currently subject to the requirement to develop and submit a risk management plan. However, this requirement is included in the permit as an applicable requirement because the permittee has an ongoing responsibility to submit a risk management plan if a substance is listed that the facility has in quantities over the threshold amount, or if the facility ever increases the amount of any regulated substance above the threshold quantity. Including this term in the permit minimizes the need to reopen the permit if the facility becomes subject to the requirement to submit a risk management plan.

Permit Conditions 3.19 and 3.20 address the Stratospheric Ozone and Climate Protection Program found in 40 CFR part 82. This program requires sources that handle regulated materials to meet certain procedural and certification requirements. There may be equipment at the facility that uses or contains chlorofluorocarbons (CFCs) or other materials regulated under this program. All air conditioning and refrigeration units must be maintained by certified individuals if they contain regulated materials.

Permit Condition 3.21 addresses asbestos demolition or renovation activity found in 40 CFR part 61, Subpart M (NESHAP). This program requires sources that handle asbestos-containing materials to follow specific procedures. If the permittee conducts any demolition or renovation activity at their facility, they must assure that the project is in compliance with the federal rules governing asbestos, including the requirement to conduct an inspection for the presence of asbestos. This requirement is in the permit to address any demolition or renovation activity that may occur at the facility.

Permit Conditions 3.22 through 3.30 specify the procedures that must be followed whenever the permit requires emissions testing or sampling in an emission unit-specific section of the permit. If there is a conflict between these permit conditions and an emission unit-specific permit condition, the specific permit condition governs. Concentration-based emission limits required to be corrected to a specific oxygen concentration in the flue gas often do not contain a protocol to convert measured concentrations to specified oxygen levels. Permit Condition 3.28 provides a protocol for such a conversion.

Permit Condition 3.31 describes general recordkeeping that has been added to the permit using Part 71 authority to assure that there is good documentation for any monitoring that the permittee performs.

Permit Condition 3.32 describes recordkeeping requirements that apply only if the permittee makes off-permit changes. Certain off-permit changes are allowed in Permit Condition 2.12.

Permit Condition 3.33 describe recordkeeping requirements that apply if the permittee performs open burning. The open burning recordkeeping was added using Part 71 authority. Open burning is restricted in Permit Conditions 3.4 through 3.8.

Permit Condition 3.34 includes recordkeeping that applies to fee records including the duration that the records must be maintained. The duration is consistent with that required by Title V (see Permit Condition 3.35).

Permit Condition 3.35 sets the duration that records must be maintained. Both Title V and FARR records must be maintained for five years. These two requirements have been combined (streamlined) into one permit condition. If there is ever a conflict between these requirements and a more restrictive emission unit-specific permit condition, the specific permit condition governs.

Permit Conditions 3.36 and 3.37 require the permittee to submit or correct submitted information when requested by EPA and as needed. The permittee has an ongoing obligation to assure that all data in its Title V application is correct and to notify EPA of any errors or omissions. This includes notifying Region 10 if the application no longer reflects the type of fuel actually being fired in a combustion unit. An address for submitting application correction directly to Region 10's air permitting program is included in this condition.

Permit Condition 3.38 and 3.39 describe reporting requirements that apply only if the permittee makes off-permit changes (Permit Condition 3.38) or section 502(b)(10) changes (Permit Condition 3.39). Certain off-permit changes are allowed in Permit Condition 2.12. Section 502(b)(10) changes are allowed in Permit Conditions 2.13.

Permit Condition 3.40 includes the address for submittals to Region 10 and to the Tribe. All reports and notices, except for fee payments (see Permit Condition 3.43), Part 71 permit applications (see Permit Condition 3.51) and Part 71 permit application corrections (see Permit Condition 3.37), must be sent to this address with a copy sent to the Tribe.

Permit Conditions 3.41 through 3.45 require submittal of an annual emission inventory (of actual emissions) and payment of fees for Part 71 purposes. These requirements refer to Permit Condition 4.1 for the actual due date by which fees and emissions must be submitted each year. The per-ton fee rate varies each year; contact EPA to obtain the current rate. The submittal of the emission inventory is timed to coincide with the payment of fees because annual Title V fees are based on actual emissions generated during the previous calendar year. Appendix A to this statement of basis documents the methods, techniques, and assumptions that EPA believes provide the most accurate basis for estimating actual emissions for this facility. As explained in Section 3.2 of this statement of basis, Region 10 expects the emission estimation techniques listed in this statement of basis to be used to calculate the annual emissions inventory, unless the permittee has other information showing why another technique more accurately represents emissions. Also note that the actual emission estimates differ from the facility's PTE because actual emission are calculated based on actual operations, not maximum operational capacity.

Note that the FARR emission inventory required in Permit Condition 3.46 to be reported at the same time can be combined with the Part 71 emission inventory as long as it is clear which emissions inventory is for which purpose, because the pollutant lists for each emission inventory are slightly different.

Permit Condition 3.46 requires submittal of an annual emission inventory (of actual emissions) for FARR registration purposes. Appendix A to this statement of basis documents the methods, techniques, and assumptions that EPA believes provide the most accurate basis for estimating actual emissions for this facility. As explained in Section 3.2 of this statement of basis, Region 10 expects the emission estimation techniques listed in this statement of basis to be used to calculate the annual emissions inventory, unless the permittee has other information showing why another technique more accurately represents emissions. Also note that the actual emission estimates differ from the facility's PTE because actual emission are calculated based on actual operations, not maximum operational capacity.

Note that the FARR emission inventory is required to be submitted at the same time as the Part 71 fees and emission inventory required in Permit Conditions 3.41 through 3.45. The Part 71 and FARR emission inventories can be combined as long as it is clear which emissions inventory is for which purpose, because the pollutant lists for each emission inventory are slightly different.

Permit Conditions 3.47 and 3.48 require semi-annual monitoring reports and prompt deviation reports. Determinations of deviations, continuous or intermittent compliance status, or violations of the permit are not limited to the testing or monitoring methods required by the underlying regulations or this permit. Failure to meet any permit term or permit condition, including emission standards, is considered a deviation. Other credible evidence (including any evidence admissible under the federal rules of evidence) must be considered by the source and EPA in such determinations. The timing for reporting deviations, as well as other data collected, depends on the circumstances, as explained in these permit conditions.

Permit Condition 3.49 requires an annual compliance certification. The permittee must certify compliance with the permit conditions in sections 3 through 13. The permittee does not need to annually certify compliance with the provisions in permit sections 1 or 2. Consistent with Permit Condition 2.6, however, if a permittee is aware of any information that indicates noncompliance, that information must be included in the annual compliance certification. In a year when the permit is renewed or revised, the permittee must address each permit for the time that permit was in effect. Forms for the annual compliance certifications may be obtained on the internet at https://www.epa.gov/title-v-operating-permits/epa-issued-operating-permits.

Permit Condition 3.50 requires the permittee to certify the truth, accuracy and completeness of all documents (notices, reports, data, and etc) submitted to EPA. The certification must be signed by a responsible official as defined in 40 CFR 71.2. The facility's responsible officials are listed on the first page of the permit. The permittee must request an administrative amendment of the permit if the responsible official for the facility changes.

Permit Conditions 3.51 and 3.52 require the permittee to submit an application for renewal and describe some of the information that must be included in the application. As explained in Permit Conditions 2.9 through 2.11, failure to submit a complete application on time terminates the permittee's right to operate. The expiration date of the permit is listed on the top right-hand corner of the front page of the permit. An address for submitting the renewal application directly to Region 10's air permitting program is included in Permit Condition 3.51.

Permit Section 4 – Facility-Specific Requirements

This permit section includes applicable requirements and related testing, monitoring, recordkeeping and reporting that apply either to multiple emission units or on a facility-specific basis. Unless otherwise specified, emission units are subject to the facility-specific requirements in Section 4 of the permit as well as the general and unit-specific requirements in Sections 3, 5 and 6 of the permit.

Permit Conditions 4.1 lists the due date for the annual fees and emission reports required in Permit Conditions 3.41 through 3.46.

Permit Condition 4.2 restricts Northwest Pipeline to combusting only natural gas in all emission units.

Permit Conditions 4.3 and 4.4 limit the sulfur content of the natural gas fuel burned in any combustion device, specify the method for determining compliance and specify the monitoring and recordkeeping.

Permit Condition 4.5 limits the sulfur dioxide (SO_2) emissions from each of the combustion devices at the facility (four gas compressor engines, one backup generator, one boiler and one fuel heater). As these devices are all fired on natural gas, SO_2 emissions are expected to be well below the emission limit. As an example, assuming the maximum fuel sulfur content allowed (see Permit Condition 4.3), SO_2 concentration is calculated as follows:

$$SO_2 \text{ concentration} = \frac{(\text{max fuel S}) \times (SO_2 \text{ conversion}) \times (SO_2 \text{ molar volume})}{(\text{f-factor}) \times (\text{fuel heat content}) \times SO_2 \text{ molar weight})}$$

$$= \frac{0.0000856 \times 2 \times 385\text{x}10^6 \times 1\text{x}10^6}{13096 \times 1020 \times 64}$$

$$= 77 \text{ ppmv at } 7\ \%O_2$$

where:

max fuel S =	(1.1 g/cm) / (454 g/lb) / (28.32 cf/cm) = 0.0000856 lbS/dscf, from 40 CFR 49.130
SO_2 conversion =	2 $lbSO_2$/lbS
SO_2 molar volume =	$385\text{x}10^6$ dscf/lbm
f-factor =	(8710) x (21%) / (21%-7%) = 13096 dscf/mmBtu at 7 $\%O_2$, from 40 CFR 60, Appendix A, Method 19, Table 19-2
fuel heat content =	1020 Btu/dscf, from AP-42, Section 1.4
SO_2 molar weight =	64 $lbSO_2$/lbm
conversion factor =	$1\text{x}10^6$ parts per million parts

As shown in the calculations above, the maximum potential SO_2 concentration from a combustion device, based on the regulatory limit (40 CFR 49.130) of 1.1 grams of sulfur per dry standard cubic meter, is 77 ppmv, which is less than the FARR regulatory limit of 500 ppmv. Therefore, compliance is reasonably assured through compliance with the fuel sulfur limit in 40 CFR 49.130. The records required to document that natural gas is being combusted (see Permit Condition 4.4) should also assure compliance.

Permit Condition 4.6 limits the particulate matter (PM) emissions from each of the combustion devices at the facility (four gas compressor engines, one backup generator, one boiler and one fuel heater). As these devices are all fired on natural gas, particulate matter emissions are expected to be well below the FARR standard. As an example, using the worst case emission factor (EF) for any combustion unit (gas compressors have highest EF per heat input), particulate matter concentration is calculated as follows:

$$\text{PM concentration} = \frac{(\text{EF}) \times (\text{conversion factor})}{(\text{f-factor})}$$

$$= \frac{0.0483 \times 7000}{13096}$$

$$= 0.026 \text{ gr/dscf at } 7\% \ O_2$$

where:

EF = 0.0483 lb/mmBtu, from Table 3.2-1, AP-42, July 2000.

conversion factor = 7000 grains/lb

f-factor = (8710) x (21%) / (21%-7%) = 13096 dscf/mmBtu at 7% O_2, from 40 CFR 60, Appendix A, Method 19, Table 19-2

As shown in the calculations above, the maximum potential PM concentration from combustion of natural gas is expected to be approximately 0.026 gr/dscf at 7% O_2, which is much lower than the applicable FARR regulatory limit of 0.1 gr/dscf at 7% O_2. Because of this margin of compliance, additional monitoring is not required in this permit. The records required to document that natural gas is being combusted (see Permit Condition 4.3) should also assure compliance.

Permit Conditions 4.7 through 4.13 require a quarterly survey (also called a plant walkthrough) for visible and fugitive emissions as well as specific follow-up steps (investigation, corrective action, RM9 observation and additional recordkeeping and reporting) if visible or fugitive emissions are observed. If observed visible or fugitive emissions cannot be eliminated within 24 hours, a tiered sequence of RM9 opacity determinations must be performed beginning with an initial 30-minute period of readings every 15 seconds. The frequency (e.g. daily or weekly) for conducting follow-up RM9 opacity readings is based upon whether any 6-minute average opacity exceeds 20%. Observations of visible or fugitive emissions during a survey are not considered deviations; however, any resulting RM9 6-minute average opacity determination above 20% is considered a permit deviation pursuant to Permit Conditions 3.47 and 3.48. The annual fugitive particulate matter survey required in Permit Condition 3.13 can be accomplished simultaneously with a quarterly survey required in this permit condition as long as both requirements are fully complied with. Not every emission generating activity is a potential source of fugitive dust or visible emissions. For example, Unit #11 (oil storage tanks) are not potential sources of fugitive dust or visible particulate matter emissions. Permit Condition 4.7, written slightly different from previous renewal Permit No. R10T5110100, clarifies that the plant walkthrough requirement only applies to emission generating activities that are a potential source of fugitive dust or visible emissions.

This permit condition serves as the periodic monitoring for several fugitive and particulate matter limits found in the permit. This requirement applies to emission sources that normally do not exhibit visible or fugitive emissions. If the permittee prefers a specific periodic monitoring approach for any emission sources subject to this requirement, the permittee can propose a new approach as a permit modification.

Permit Conditions 4.14 and 4.15. have been include in the permit because a December 2002 change to the PSD regulation applicability test for modifications resulted in a new applicable requirement for PSD major sources. In summary, when the permittee considers a plant modification project to be exempt from PSD via the method specified in 40 CFR 52.21(b)(41)(ii)(a) through (c) and there is a reasonable possibility that there will be a significant emissions increase resulting from the project, then the permittee must fulfill specified requirements related to documentation, monitoring, and notification. This requirement will be relevant to the facility only when the permittee is contemplating making physical or operational changes to the facility. In those instances, it is strongly recommended that the permittee contact Region 10 to discuss their plans and verify their assumptions.

Permit Conditions 4.16 through 4.19 are generally applicable requirements that apply to the facility's emission units subject to a NESHAP; emergency backup RICE (Unit #5) and the boiler and fuel gas heater (Units #6 and 7). Permit Condition 4.17, written slightly different from previous renewal Permit No. R10T5110100, clarifies that the on-site data retention requirement does not apply to Unit #5 pursuant to 40 CFR 63.6665 and Table 8 to Subpart ZZZZ of Part 63.

Permit Section 5 – Unit-Specific Requirements – NESHAP Subpart ZZZZ for Unit #5 (Emergency Generator Engine)

Permit Conditions 5.1 through 5.11 are MACT ZZZZ requirements to properly operate and maintain an emergency stationary RICE. If the permittee does not operate the engine according to the requirements in 40 CFR 63.6640(f)(1) through (4), the engine will not be considered an emergency engine under NESHAP Subpart ZZZZ and must meet all requirements for non-emergency engines. There is no time limit on the use of the engine in emergency situations.

Permit Conditions 5.12 through 5.15 are MACT ZZZZ monitoring and recordkeeping requirements. Northwest Pipeline is required to track hours of operation, and this provides Northwest Pipeline with information useful to calculate its actual emissions.

Permit Conditions 5.16 through 5.19 are MACT ZZZZ reporting requirements. With issuance of this Title V permit, EPA is specifying when certain MACT ZZZZ reports must be submitted.

Permit Section 6 – Unit-Specific Requirements – NESHAP Subpart DDDDD for Units #6 (Boiler) and 7 (Process Heater)

Permit Condition 6.1 requires tune-ups of the Units #6 and 7 every five years (no later than 61 months from previous tune-up) and specifies what must be included in the tune-ups. The date of the latest tune-up conducted on Unit #6 is November 12, 2015. The date of the latest tune-up conducted on Unit #7 is December 15, 2015. The next tune-up for Unit #6 and 7 shall be conducted no later than December 31, 2020 and January 31, 2021, respectively. If the unit is not operating on its scheduled tune-up due date noted above, the tune-up must be conducted within 30 calendar days of the day it first operates after the scheduled tune-up due date.

Permit Condition 6.2 is the general NESHAP requirement to employ good air pollution control practices that was written specifically for boilers and process heaters subject to the major source MACT.

Permit Condition 6.3 specifies the records that must be maintained consistent with Condition 4.17. Conditions 6.3 and 4.17 should be read together. Condition 6.3.5 clarifies that records only have to be kept onsite for the first two of the required five years.

Permit Condition 6.4 requires annual compliance reports and describes the contents of the reports and technique for submittal. For a tune-up completed in 2020, the associated compliance report must be postmarked or submitted by January 31, 2021. For a tune-up completed in 2021, the associated compliance report must be postmarked or submitted by January 31, 2022. Unlike the previous renewal permit, this renewal requires the compliance report to contain the following information that is already required to be recorded pursuant to 40 CFR 63.7540(a)(10)(vi):

- The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler; and
- A description of any corrective actions taken as a part of the tune-up.

Permit Condition 6.5 requires notification when switching fuels.

5.2 Obsolete Permit Conditions from Expiring Permit No. R10T5110100

Northwest Pipeline has satisfied several one-time NESHAP requirements since issuance of previous renewal Permit No. R10T5110100 on September 30, 2015. The requirements are no longer relevant to the operation of the source. In other words, the requirements are obsolete. These requirements are not being carried forward in the proposed renewal Permit No. R10T5110200. Each obsolete permit condition from Permit No. R10T5110100 is generally explained below.

Permit Condition 4.19 required the permittee to submit a notification of compliance status (NOCS) with respect to NESHAP Subpart DDDDD for Units #6 and 7. The permittee fulfilled this requirement when the EPA received Northwest Pipeline's NESHAP Subpart DDDDD NOCS on February 26, 2016. This requirement did not apply to Unit #5 as the permittee would have already been required (if applicable) to submit a NOCS prior to issuance of Permit No. R10T5110100 on September 30, 2015. The MACT ZZZZ compliance date was May 3, 2013.

Permit Condition 5.16.2 required, in part, the first NESHAP ZZZZ annual report be submitted no later than March 31, 2016. The EPA could not find a report documenting this submittal for calendar year 2015. The agency assumes that the engine must not have operated for more than 15 hours for the purposes specified in Permit Conditions 5.7.2 and 5.7.3.

Permit Conditions 6.1.1 and 6.1.2 required, in part, the initial tune-up of Units #6 and 7 be conducted no later than January 31, 2016 (or not later than 30 days after re-start of that unit if not operated between January 31, 2013 and January 31, 2016). The permittee provided evidence of having satisfied this requirement in a NESHAP Subpart DDDDD NOCS received on February 26, 2016.Permit Condition 6.2 required the permittee to conduct a one-time energy assessment of Units #6 and 7 (and major energy use systems consuming energy from the units) no later than January 31, 2016. The permittee provided evidence of having satisfied this requirement in a NESHAP Subpart DDDDD NOCS received on February 26, 2016. According to the NOCS, Sage Environmental Consulting was contracted to conduct the Energy Assessment and transmitted the energy assessment to Northwest Pipeline on September 9, 2015.

Permit Condition 6.5 required the permittee to submit a NESHAP Subpart DDDDD NOCS for Units #6 and 7. As stated above, EPA received from the permittee a NESHAP Subpart DDDDD NOCS on February 26, 2016.

Permit Condition 6.6.1 required the permittee to submit the first NESHAP Subpart DDDDD annual compliance report covering the time period of January 31, 2016 to December 31, 2016. This first report was due on January 31, 2017. The permittee submitted this report on January 31, 2020. According to the permittee, there were no deviations from the requirements for work practice standards during the reported period.

6. Public Participation

6.1 Public Notice and Comment

As required in 40 CFR 71.11(a)(5) and 71.8, all draft operating permits must be publicly noticed and made available for public comment. The public notice of permit actions and public comment period is described in 40 CFR 71.11(d). There is a 30 day public comment period for actions pertaining to a draft permit. For this permit action, the requirements of 40 CFR 71.11(a)(5) and 71.8 will be satisfied as follows:

1. Posting the public notice, draft permit, statement of basis and the draft administrative record (which includes the application and relevant supporting materials) on EPA's website for the duration of the public comment period.

2. Providing a copy of the public notice to: the permit applicant, the affected states, the air pollution control agencies of affected states, the Tribal, city and county executives, any comprehensive land use planning agency, any state or federal land manager whose lands may be affected by emissions from the source, the local emergency planning authorities which have jurisdiction over the area where the source is located and all persons who submitted a written request to be included on the EPA's mailing list for Title V permitting actions.

6.2 Response to Public Comments and Permit Issuance

The public comment process was held as described above. No requests for a public hearing were received. No comments were received during the public comment period. Because no comments were received, the final permit decision becomes effective immediately upon issuance pursuant to 40 CFR 71.11(i)(2)(iii).

Appendix A

EPA Estimation of Northwest Pipeline
Pocatello Compressor Station
Potential Air Pollutant Emissions

Statement of Basis

Title V Air Quality Operating Permit Renewal #2

R10T5110200

Pocatello, Idaho

Summary of Facility Non-HAP Potential Emissions

Non-Fugitive Emissions[1] (tons per year)

	EU-1,2&3	EU-4	EU-5	EU-6	EU-7	EU-8	EU-9	EU-10	EU-11	
	Three Clark TLA-6 RICE	Clark TCV-10 RICE	Caterpillar 3408 RICE Backup Generator	Sellers Boiler	Sivallis Fuel Gas Heater	Heaters and Furnaces	System Blowdown Gas	Equipment Leaks	Liquid Storage Tanks	**Non-Fugitive Subtotal**
Carbon Monoxide (CO)	67.3	33.0	3.5	1.3	0.2	0.4				106
Hydrogen Sulfide (H_2S)							0.01			0
Lead (Pb)	9.5E-05	4.7E-05	4.6E-07	7.5E-06	1.1E-06	2.5E-06	8.8E-08			0
Nitrogen Oxides (NO_X)	730.0	357.5	2.1	1.5	0.2	0.5				1,092
Particulate (PM)[2]	7.5	3.7	0.01	0.03	0.004	0.01				11
Inhalable Coarse Particulate (PM_{10})	9.4	4.5	0.02	0.1	0.02	0.04				14
Fine Particulate ($PM_{2.5}$)	9.4	4.5	0.02	0.1	0.02	0.04				14
Sulfur Dioxide (SO_2)	10.6	5.2	0.1	0.8	0.1	0.3				17
Volatile Organic Compounds (VOC)	21.8	10.7	0.03	0.1	0.01	0.03	0.2		0.4	33
Greenhouse Gas (CO_2e)	22,772	11,152	110	1,803	256	605	178			36,876

Fugitive Emissions, (tons per year)

	EU-1,2&3	EU-4	EU-5	EU-6	EU-7	EU-8	EU-9	EU-10	EU-11	
	Three Clark TLA-6 RICE	Clark TCV-10 RICE	Caterpillar 3408 RICE Backup Generator	Sellers Boiler	Sivallis Fuel Gas Heater	Heaters and Furnaces	System Blowdown Gas	Equipment Leaks	Liquid Storage Tanks	**Fugitive Subtotal**
Carbon Monoxide (CO)										0
Hydrogen Sulfide (H_2S)								0.01		0
Lead (Pb)								8.8E-08		0
Nitrogen Oxides (NO_X)										0
Particulate (PM)[2]										0
Inhalable Coarse Particulate (PM_{10})										0
Fine Particulate ($PM_{2.5}$)										0
Sulfur Dioxide (SO_2)										0
Volatile Organic Compounds (VOC)								0.2		0
Greenhouse Gas (CO_2e)								178		178

Total Non-Fugitive and Fugitive Emissions, (tons per year)

	EU-1,2&3	EU-4	EU-5	EU-6	EU-7	EU-8	EU-9	EU-10	EU-11	
	Three Clark TLA-6 RICE	Clark TCV-10 RICE	Caterpillar 3408 RICE Backup Generator	Sellers Boiler	Sivallis Fuel Gas Heater	Heaters and Furnaces	System Blowdown Gas	Equipment Leaks	Liquid Storage Tanks	**Plantwide PTE**
Carbon Monoxide (CO)	67.3	33.0	3.5	1.3	0.2	0.4				106
Hydrogen Sulfide (H_2S)							0.01	0.01		0
Lead (Pb)	9.5E-05	4.7E-05	4.6E-07	7.5E-06	1.1E-06	2.5E-06	8.8E-08	8.8E-08		0
Nitrogen Oxides (NO_X)	730.0	357.5	2.1	1.5	0.2	0.5				1,092
Particulate (PM)[2]	7.5	3.7	0.01	0.03	0.004	0.01				11
Inhalable Coarse Particulate (PM_{10})	9.4	4.5	0.02	0.1	0.02	0.04				14
Fine Particulate ($PM_{2.5}$)	9.4	4.5	0.02	0.1	0.02	0.04				14
Sulfur Dioxide (SO_2)	10.6	5.2	0.1	0.8	0.1	0.3				17
Volatile Organic Compounds (VOC)	21.8	10.7	0.03	0.1	0.01	0.03	0.2	0.2	0.4	33
Greenhouse Gas (CO_2e)	22,772	11,152	110	1,803	256	605	178	178		37,054

Notes:

[1] Only non-fugitive emissions are considered for this facility in determining Title V applicability given that it is a natural gas compressor station and not one of the 27 listed source categories required to consider fugitive emissions. See definition of "major source" at 40 CFR § 71.2.

[2] PM is not a pollutant considered in determining whether a source is subject to the requirement to obtain a Title V permit; however, PM emissions are considered in determining whether a facility/project is a major PSD source/modification and whether a source is subject to compliance assurance monitoring.

Summary of Facility HAP Potential to Emit

Total Non-Fugitive and Fugitive Emissions, (tons per year)

Hazardous Air Pollutants (HAP)	EU-1,2&3 Three Clark TLA-6 RICE	EU-4 One Clark TCV-10 RICE	EU-5 One Caterpillar 3408 RICE Backup Generator	EU-6 Sellers Boiler	EU-7 Sivallis Fuel Gas Heater	EU-8 Heaters and Furnaces	EU-9 System Blowdown Gas	EU-10 Equipment Leaks	EU-11 Liquid Storage Tanks	Single HAP Plantwide Totals
Trace Metal Compounds										
Arsenic Compounds	3.81E-05	1.87E-05	1.84E-07	3.02E-06	4.29E-07	1.01E-06				6.1E-05
Beryllium Compounds	2.29E-06	1.12E-06	1.11E-08	1.81E-07	2.58E-08	6.08E-08				3.7E-06
Cadmium Compounds	2.10E-04	1.03E-04	1.01E-06	1.66E-05	2.36E-06	5.57E-06				3.4E-04
Chromium Compounds (including hexavalent)	2.67E-04	1.31E-04	1.29E-06	2.11E-05	3.01E-06	7.09E-06				4.3E-04
Cobalt Compounds	1.60E-05	7.84E-06	7.74E-08	1.27E-06	1.80E-07	4.25E-07				2.6E-05
Manganese Compounds	7.25E-05	3.55E-05	3.50E-07	5.74E-06	8.16E-07	1.92E-06				1.2E-04
Mercury Compounds	4.96E-05	2.43E-05	2.40E-07	3.92E-06	5.58E-07	1.32E-06				8.0E-05
Nickel Compounds	4.00E-04	1.96E-04	1.94E-06	3.17E-05	4.51E-06	1.06E-05				6.5E-04
Selenium Compounds	4.58E-06	2.24E-06	2.21E-08	3.62E-07	5.15E-08	1.22E-07				7.4E-06
Organic Compounds										
1,1,2,2-Tetrachlorethane	1.29E-02	6.31E-03	2.38E-05							1.9E-02
1,1,2-Trichloroethane	1.02E-02	5.02E-03	1.44E-04							1.5E-02
1,3-Butadiene	1.59E-01	7.81E-02	6.23E-04							2.4E-01
1,3-Dichloropropene	8.52E-02	4.17E-02	1.19E-05							1.3E-01
2,2,4-Trimethylpentane	1.65E-01	8.06E-02								2.5E-01
Acetaldehyde	1.51E+00	7.39E-01	2.62E-03							2.3E+00
Acrolein	1.51E+00	7.41E-01	2.47E-03							2.3E+00
Benzene	3.77E-01	1.85E-01	1.49E-03	3.17E-05	4.51E-06	1.06E-05				5.6E-01
Biphenyl	7.68E-04	3.76E-04								1.1E-03
Carbon Tetrachloride	1.18E-02	5.78E-03	1.66E-05							1.8E-02
Chlorobenzene	8.63E-03	4.23E-03	1.21E-05							1.3E-02
Chloroform	9.16E-03	4.49E-03	1.29E-05							1.4E-02
Dichlorobenzene				1.81E-05	2.58E-06	6.08E-06				2.7E-05
Ethylbenzene	2.10E-02	1.03E-02	2.33E-05							3.1E-02
Ethylene Dibromide	1.43E-02	6.99E-03	2.00E-05							2.1E-02
Formaldehyde	1.07E+01	5.26E+00	1.93E-02	1.13E-03	1.61E-04	3.80E-04				1.6E+01
Methanol	4.82E-01	2.36E-01	2.88E-03							7.2E-01
Methylene Chloride	2.86E-02	1.40E-02	3.87E-05							4.3E-02
n-Hexane	8.65E-02	4.24E-02		1.13E-03	1.61E-04	9.11E-03	5.58E-03	5.58E-03		1.5E-01
Naphthalene[1]	1.87E-02	9.17E-03	9.13E-05	9.21E-06	1.31E-06	3.09E-06				2.8E-02
Phenol	8.19E-03	4.01E-03								1.2E-02
Polycyclic Organic Matter (POM)[2]	6.28E-02	3.07E-02	1.33E-04	1.05E-05	1.50E-06	3.54E-06				9.4E-02
Styrene	1.07E-02	5.22E-03	1.12E-05							1.6E-02
Toluene	1.87E-01	9.17E-02	5.25E-04	5.13E-05	7.30E-06	1.72E-05				2.8E-01
Vinyl Chloride	4.80E-03	2.35E-03	6.75E-06							7.2E-03
Xylene	5.21E-02	2.55E-02	1.83E-04							7.8E-02
TOTAL[2]	15.6	7.6	0.03	0.002	0.0003	0.01	0.01	0.01	0	

Predicted Highest Plantwide Single HAP	16.0	tons per year, formaldehyde
Predicted Plantwide HAP Total	23.2	tons per year, based on summing estimates

[1] designates a HAP that is subject individually to the 10 tpy major source threshold, but that is also one of several polycyclic organic matter (POM) compounds that, in aggregate, are subject to the same 10 tpy major source threshold.

[2] Because naphthalene is accounted for individually and in the calculation of POM EF, its individual contribution here is discounted so as to avoid double-counting.

Non-HAP Potential to Emit

Emission Unit:	**EU-1, 2 and 3**
Description:	Clark TLA-6 Reciprocating IC Compressor Engines, two-stroke, lean-burn, spark ignition
Control Device:	none
Fuel:	natural gas
Installation Date:	1956
Design Maximum Output Capacity:	2,000 horsepower at 300 rpm
Design Maximum Heat Input Capcity:	14.8 MMBtu/hr
Operation:	8760 hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	Per Engine EF (lb/MMBtu)	Per Engine PTE (tpy)	All Three Engines PTE (tpy)	EF Reference
Carbon Monoxide (CO)	0.346	22.4	67.3	1
Lead (Pb)	4.90E-07	0.00003	0.0001	2
Nitrogen Oxides (NO_X)	3.754	243.3	730.0	1
Particulate (PM)	0.0384	2.5	7.5	3
Inhalable Coarse Particulate (PM_{10})	0.0483	3.1	9.4	3
Fine Particulate ($PM_{2.5}$)	0.0483	3.1	9.4	3
Sulfur Dioxide (SO_2)	0.0544	3.5	10.6	4
Volatile Organic Compounds (VOC)	0.112	7.3	21.8	1

NON-FUGITIVE EMISSIONS

Greenhouse Gas Emissions (CO_2 Equivalent)	Per Engine EF (lb/MMBtu)	Per Engine PTE (tpy)	All Three Engines PTE (tpy)	EF Reference
Carbon Dioxide (CO_2)	116.977	7582.9	22748.8	5
Methane (CH_4)	0.055	3.6	10.7	5
Nitrous Oxide (N_2O)	0.066	4.3	12.8	5
TOTAL		7,591	22,772	

EF Reference	Description
1	EU-1 performance test conducted June 11, 1998 at full load (~100%) and reduced load (~85%). Emission factors employed in this PTE EI are worst-case (i.e. NO_X and VOC at full load and CO at reduced load.
2	Table 1.4-2 of AP-42, July 1998. EF (lb/MMBtu) = (0.0005 lb/1x10^6 scf) X (1x10^6 scf/1020 MMBtu). See footnote a to Table 1.4-2.

EF Reference 3

Table 3.2-1 of AP-42, July 2000. Filterable PM (≤ 1μm) = 3.84x10^{-2} lb/MMBtu. Condensible PM ~ 9.91x10^{-3} lb/MMBtu. PM EF equal to filterable portion. PM_{10} and $PM_{2.5}$ EF equal to sum of both; 0.0483 lb/MMBtu. EPA did not employ the applicable FARR PM limit to calculate potential emissions because the resultant 0.1871 lb/MMBtu PM EF is unrealistic for a natural gas fired engine. The calculation to derive the 0.1871 lb/MMBtu PM EF is as follows:

Basis: FARR combustion source stack PM emission limit of 0.1 gr/dscf corrected to 7% O_2 at 40 CFR 49.125(d)(1)

EF (lb/MMBtu) = FARR PM Limit (gr/dscf@7%O_2) X $CF_{7\rightarrow0\%O2}$ X F_d (dscf/MMBtu) / $CF_{gr\rightarrow lb}$ (gr/lb)

• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR PM Calculated EF (lb/MMBtu)	FARR PM Emission Limit (gr/dscf @7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	F_d (dscf/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)
0.1871	0.1	1.504	8,710	7,000

EF Reference 4

<u>Option 1</u>: 0.0544 lb/MMBtu. This emission factor is employed to determine PTE as it limits emissions to less than Option 2 or 3 below.

Basis: FERC natural gas pipeline tariff sulfur limit of 20 gr/100 standard cubic feet.

EF (lb/MMBtu) = Pipeline tariff S Limit (gr/100 ft^3) / $CF_{100ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{gr\rightarrow lb}$ X $CF_{S\rightarrow SO2}$

• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.

• $CF_{ft3\rightarrow Btu}$ = 105000 Btu/100 ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

Pipeline Tariff Calculate SO_2 EF (lb/MMBtu)	Pipeline Tariff Fuel Sulfur Limit (gr/100 ft^3)	$CF_{ft3\rightarrow Btu}$ (Btu/100 ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.0544	20	105000	1.E+06	7000	2

<u>Option 2</u>: 0.1308 lb/MMBtu.

Basis: FARR gaseous fuel sulfur limit of 1.1 g/dry standard cubic meter at 40 CFR 49.130(d)(8)

EF (lb/MMBtu) = FARR Fuel S Limit (g/m^3) / $CF_{m3\rightarrow ft3}$ / $CF_{ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{g\rightarrow lb}$ X $CF_{S\rightarrow SO2}$

• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.

• $CF_{ft3\rightarrow Btu}$ = 1050 Btu/ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

FARR Fuel S Calculate SO_2 EF (lb/MMBtu)	FARR Fuel Sulfur Limit (g/m^3)	$CF_{m3\rightarrow ft3}$ (ft^3/m^3)	$CF_{ft3\rightarrow Btu}$ (Btu/ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{g\rightarrow lb}$ (g/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.1308	1.1	35.3147	1050	1.E+06	453.592	2

<u>Option 3</u>: 1.087 lb/MMBtu.

Basis: FARR combustion source stack SO_2 emission limit of 500 parts per million by volume dry basis (ppmvd) corrected to 7% O_2 at 40 CFR 49.129(d)(1)

EF (lb/MMBtu) = FARR SO_2 Limit (ppmvd@7%O_2) X $CF_{7\rightarrow0\%O2}$ X $CF_{ppm\rightarrow lb/dscfSO2}$ X F_d (dscf/MMBtu)

• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• $CF_{ppm\rightarrow lb/dscfSO2}$ = 1.660 X 10^{-7} lb SO_2/dscf / ppm SO_2. See Table 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR 500 ppm Calculate SO_2 EF (lb/MMBtu)	FARR SO_2 Emission Limit (ppmvd@7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	$CF_{ppm\rightarrow lb/dscfSO2}$ (lb/dscf / ppm)	F_d (dscf/MMBtu)
1.087	500	1.504	1.66E-07	8710

EF Reference 5

EPA's March 2011 guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" states that the GHG Report Rule (40 CFR 98), "should be considered a primary reference for sources and permitting authorities in estimating GHG emissions and establishing measurement techniques when preparing or processing permit applications." Therefore, GHG Reporting Rule emission factors will be employed to determine GHG PTE.

<u>Carbon Dioxide (CO_2)</u>

EF (lb CO_2e/MMBtu) = EF (kg CO_2/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CO2} (lb CO_2e/lb CO_2)

Calculated CO_2e EF for CO_2 (lb CO_2e/MMBtu)	40 CFR 98 Table C-1 EF (kg CO_2/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CO_2)
116.977	53.06	2.20462262	1

<u>Methane (CH_4)</u>

EF (lb CO_2e/MMBtu) = EF (kg CH_4/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CH4} (lb CO_2e/lb CH_4)

Calculated CO_2e EF for CH_4 (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg CH_4/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CH_4)
0.055	0.001	2.20462262	25

<u>Nitrous Oxide (N_2O)</u>

EF (lb CO_2e/MMBtu) = EF (kg N_2O/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{N2O} (lb CO_2e/lb N_2O)

Calculated CO_2e EF for N_2O (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg N_2O/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb N_2O)
0.066	0.0001	2.20462262	298

HAP Potential to Emit

Emission Unit:	**EU-1, 2 and 3**
Description:	Clark TLA-6 Reciprocating IC Compressor Engines, two-stroke, lean-burn, spark ignition
Control Device:	none
Fuel:	natural gas
Installation Date:	1956
Design Maximum Output Capacity:	2,000 horsepower at 300 rpm
Design Maximum Heat Input Capcity:	14.8 MMBtu/hr
Operation:	8760 hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	Per Engine EF (lb/1x10^6 scf)	Per Engine EF (lb/MMBtu)	Per Engine PTE (tpy)	All Three Engines PTE (tpy)
Trace Metal Compounds				
Arsenic Compounds	2.0E-04	2.0E-07	1.27E-05	3.81E-05
Beryllium Compounds	1.2E-05	1.2E-08	7.63E-07	2.29E-06
Cadmium Compounds	1.1E-03	1.1E-06	6.99E-05	2.10E-04
Chromium Compounds (including hexavalent)	1.4E-03	1.4E-06	8.90E-05	2.67E-04
Cobalt Compounds	8.4E-05	8.2E-08	5.34E-06	1.60E-05
Manganese Compounds	3.8E-04	3.7E-07	2.42E-05	7.25E-05
Mercury Compounds	2.6E-04	2.5E-07	1.65E-05	4.96E-05
Nickel Compounds	2.1E-03	2.1E-06	1.33E-04	4.00E-04
Selenium Compounds	2.4E-05	2.4E-08	1.53E-06	4.58E-06
Organic Compounds				
1,1,2,2-Tetrachlorethane	Not Applicable	6.63E-05	4.30E-03	1.29E-02
1,1,2-Trichloroethane		5.27E-05	3.42E-03	1.02E-02
1,3-Butadiene		8.20E-04	5.32E-02	1.59E-01
1,3-Dichloropropene		4.38E-04	2.84E-02	8.52E-02
2,2,4-Trimethylpentane		8.46E-04	5.48E-02	1.65E-01
Acetaldehyde		7.76E-03	5.03E-01	1.51E+00
Acrolein		7.78E-03	5.04E-01	1.51E+00
Benzene		1.94E-03	1.26E-01	3.77E-01
Biphenyl		3.95E-06	2.56E-04	7.68E-04
Carbon Tetrachloride		6.07E-05	3.93E-03	1.18E-02
Chlorobenzene		4.44E-05	2.88E-03	8.63E-03
Chloroform		4.71E-05	3.05E-03	9.16E-03
Ethylbenzene		1.08E-04	7.00E-03	2.10E-02
Ethylene Dibromide		7.34E-05	4.76E-03	1.43E-02
Formaldehyde		5.52E-02	3.58E+00	1.07E+01
Methanol		2.48E-03	1.61E-01	4.82E-01
Methylene Chloride		1.47E-04	9.53E-03	2.86E-02
n-Hexane		4.45E-04	2.88E-02	8.65E-02
Naphthalene[1]		9.63E-05	6.24E-03	1.87E-02
Phenol		4.21E-05	2.73E-03	8.19E-03
Polycyclic Organic Matter (POM)[2]		3.23E-04	2.09E-02	6.28E-02
Styrene		5.48E-05	3.55E-03	1.07E-02
Toluene		9.63E-04	6.24E-02	1.87E-01
Vinyl Chloride		2.47E-05	1.60E-03	4.80E-03
Xylene		2.68E-04	1.74E-02	5.21E-02
TOTAL[3]		8.00E-02	5.2	15.6

[1] Naphthalene is a HAP that is subject individually to the 10 tpy major source threshold, but that is also one of several polycyclic organic matter (POM) compounds that, in aggregate, are subject to the same 10 tpy major source threshold.

[2] See table below for list of individual polycyclic organic matter (POM) compounds. POM defines a broad class of compounds that generally includes all organic structures having two or more fused aromatic rings (i.e., rings that share a common border), and that have a boiling point greater than or equal to 212°F (100°C). See http://www.epa.gov/ttn/atw/hlthef/polycycl.html#ref11

[3] Because naphthalene is accounted for individually and in the calculation of POM EF, its contribution here is discounted so as to avoid double-counting.

Trace Metal Compounds EF Basis: AP-42, Table 1.4-4, July 1998.
EF (lb/MMBtu) = EF (lb/1x10^6 scf) X (1x10^6 scf/1020 MMBtu). See footnote a to Table 1.4-4.

Organic Compounds EF Basis: AP-42, Table 3.2-1, July 2000.

POM Compounds	EF (lb/MMBtu)
2-Methylnaphthalene*	2.14E-04
Acenaphthene*	1.33E-06
Acenaphthylene*	3.17E-06
Anthracene*	7.18E-07
Benzo(a)anthracene*	3.36E-07
Benzo(a)pyrene*	5.68E-09
Benzo(b)fluoranthene*	8.51E-09
Benzo(e)pyrene*	2.34E-08
Benzo(g,h,l)perylene*	2.48E-08
Benzo(k)fluoranthene*	4.26E-09
Chrysene*	6.72E-07
Fluoranthene*	3.61E-07
Fluorene*	1.69E-06
Indeno(1,2,3-cd)pyrene*	9.93E-09
Naphthalene*,**	9.63E-05
Perylene*	4.97E-09
Phenanthrene*	3.53E-06
Pyrene*	5.84E-07
SUBTOTAL	3.23E-04

* designates a polycyclic aromatic hydrocarbon (PAH). PAHs are potent atmospheric pollutants that consist of fused aromatic rings and do not contain heteroatoms or carry substituents. See http://en.wikipedia.org/wiki/Polycyclic_aromatic_hydrocarbon#PAH_compounds

** designates a POM compound that is also an individual HAP.

Non-HAP Potential to Emit

Emission Unit: **EU-4**
Description: Clark TCV-10 Reciprocating IC Compressor Engines, two-stroke, lean-burn, spark ignition
Control Device: none
Fuel: natural gas
Installation Date: 1969
Design Maximum Output Capacity: 3,400 horsepower at 300 rpm
Design Maximum Heat Input Capcity: 21.743 MMBtu/hr
Operation: 8760 hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Monoxide (CO)	0.346	33.0	1
Lead (Pb)	4.90E-07	0.00005	2
Nitrogen Oxides (NO_X)	3.754	357.5	1
Particulate (PM)	0.0384	3.7	3
Inhalable Coarse Particulate (PM_{10})	0.0475	4.5	3
Fine Particulate ($PM_{2.5}$)	0.0475	4.5	3
Sulfur Dioxide (SO_2)	0.0544	5.2	4
Volatile Organic Compounds (VOC)	0.112	10.7	1

NON-FUGITIVE EMISSIONS

Greenhouse Gas Emissions (CO_2 Equivalent)	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Dioxide (CO_2)	116.977	11140.3	5
Methane (CH_4)	0.055	5.2	5
Nitrous Oxide (N_2O)	0.066	6.3	5
TOTAL		11,152	

<table>
<tr><th>EF Reference</th><th>Description</th></tr>
<tr><td>1</td><td>EU-1 performance test conducted June 11, 1998 at full load (~100%) and reduced load (~85%). Emission factors employed in this PTE EI are worst-case (i.e. NO_X and VOC at full load and CO at reduced load.</td></tr>
<tr><td>2</td><td>Table 1.4-2 of AP-42, July 1998. EF (lb/MMBtu) = (0.0005 lb/1x10^6 scf) X (1x10^6 scf/1020 MMBtu). See footnote a to Table 1.4-2.</td></tr>
<tr><td>3</td><td>Table 3.2-1 of AP-42, July 2000. Filterable PM (≤ 1μm) = 3.84×10^{-2} lb/MMBtu. Condensible PM ~ 9.91×10^{-3} lb/MMBtu. PM EF equal to filterable portion. PM_{10} and $PM_{2.5}$ EF equal to sum of both; 0.0483 lb/MMBtu. EPA did not employ the applicable FARR PM limit to calculate potential emissions because the resultant 0.1871 lb/MMBtu PM EF is unrealistic for a natural gas fired engine. The calculation to derive the 0.1871 lb/MMBtu PM EF is as follows:
Basis: FARR combustion source stack PM emission limit of 0.1 gr/dscf corrected to 7% O_2 at 40 CFR 49.125(d)(1)
EF (lb/MMBtu) = FARR PM Limit (gr/dscf@7%O_2) X $CF_{7\rightarrow0\%O2}$ X F_d (dscf/MMBtu) / $CF_{gr\rightarrow lb}$ (gr/lb)
• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.
• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR PM Calculated EF (lb/MMBtu)	FARR PM Emission Limit (gr/dscf @7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	F_d (dscf/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)
0.1871	0.1	1.504	8,710	7,000
</td></tr>
<tr><td>4</td><td><u>Option 1</u>: 0.0544 lb/MMBtu. This emission factor is employed to determine PTE as it limits emissions to less than Option 2 or 3 below.
Basis: FERC natural gas pipeline tariff sulfur limit of 20 gr/100 standard cubic feet.
EF (lb/MMBtu) = Pipeline tariff S Limit (gr/100 ft^3) / $CF_{100ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{gr\rightarrow lb}$ X $CF_{S\rightarrow SO2}$
• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.
• $CF_{ft3\rightarrow Btu}$ = 105000 Btu/100 ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

Pipeline Tariff Calculate SO_2 EF (lb/MMBtu)	Pipeline Tariff Fuel Sulfur Limit (gr/100 ft^3)	$CF_{ft3\rightarrow Btu}$ (Btu/100 ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.0544	20	105000	1.E+06	7000	2

<u>Option 2</u>: 0.1308 lb/MMBtu.
Basis: FARR gaseous fuel sulfur limit of 1.1 g/dry standard cubic meter at 40 CFR 49.130(d)(8)
EF (lb/MMBtu) = FARR Fuel S Limit (g/m^3) / $CF_{m3\rightarrow ft3}$ / $CF_{ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{g\rightarrow lb}$ X $CF_{S\rightarrow SO2}$
• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.
• $CF_{ft3\rightarrow Btu}$ = 1050 Btu/ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

FARR Fuel S Calculate SO_2 EF (lb/MMBtu)	FARR Fuel Sulfur Limit (g/m^3)	$CF_{m3\rightarrow ft3}$ (ft^3/m^3)	$CF_{ft3\rightarrow Btu}$ (Btu/ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{g\rightarrow lb}$ (g/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.1308	1.1	35.3147	1050	1.E+06	453.592	2

<u>Option 3</u>: 1.087 lb/MMBtu.
Basis: FARR combustion source stack SO_2 emission limit of 500 parts per million by volume dry basis (ppmvd) corrected to 7% O_2 at 40 CFR 49.129(d)(1)
EF (lb/MMBtu) = FARR SO_2 Limit (ppmvd@7%O_2) X $CF_{7\rightarrow0\%O2}$ X $CF_{ppm\rightarrow lb/dscfSO2}$ X F_d (dscf/MMBtu)
• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.
• $CF_{ppm\rightarrow lb/dscfSO2}$ = 1.660 X 10^{-7} lb SO_2/dscf / ppm SO_2. See Table 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.
• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR 500 ppm Calculate SO_2 EF (lb/MMBtu)	FARR SO_2 Emission Limit (ppmvd@7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	$CF_{ppm\rightarrow lb/dscfSO2}$ (lb/dscf / ppm)	F_d (dscf/MMBtu)
1.087	500	1.504	1.66E-07	8710
</td></tr>
<tr><td>5</td><td>EPA's March 2011 guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" states that the GHG Report Rule (40 CFR 98), "should be considered a primary reference for sources and permitting authorities in estimating GHG emissions and establishing measurement techniques when preparing or processing permit applications." Therefore, GHG Reporting Rule emission factors will be employed to determine GHG PTE.
<u>Carbon Dioxide (CO_2)</u>
EF (lb CO_2e/MMBtu) = EF (kg CO_2/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CO2} (lb CO_2e/lb CO_2)

Calculated CO_2e EF for CO_2 (lb CO_2e/MMBtu)	40 CFR 98 Table C-1 EF (kg CO_2/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CO_2)
116.977	53.06	2.20462262	1

<u>Methane (CH_4)</u>
EF (lb CO_2e/MMBtu) = EF (kg CH_4/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CH4} (lb CO_2e/lb CH_4)

Calculated CO_2e EF for CH_4 (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg CH_4/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CH_4)
0.055	0.001	2.20462262	25

<u>Nitrous Oxide (N_2O)</u>
EF (lb CO_2e/MMBtu) = EF (kg N_2O/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{N2O} (lb CO_2e/lb N_2O)

Calculated CO_2e EF for N_2O (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg N_2O/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb N_2O)
0.066	0.0001	2.20462262	298
</td></tr>
</table>

HAP Potential to Emit

Emission Unit: **EU-4**
Description: Clark TCV-10 Reciprocating IC Compressor Engines, two-stroke, lean-burn, spark ignition
Control Device: none
Fuel: natural gas
Installation Date: 1969
Design Maximum Output Capacity: 3,400 horsepower at 300 rpm
Design Maximum Heat Input Capcity: 21.743 MMBtu/hr
Operation: 8760 hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)
Trace Metal Compounds			
Arsenic Compounds	2.0E-04	2.0E-07	1.87E-05
Beryllium Compounds	1.2E-05	1.2E-08	1.12E-06
Cadmium Compounds	1.1E-03	1.1E-06	1.03E-04
Chromium Compounds (including hexavalent)	1.4E-03	1.4E-06	1.31E-04
Cobalt Compounds	8.4E-05	8.2E-08	7.84E-06
Manganese Compounds	3.8E-04	3.7E-07	3.55E-05
Mercury Compounds	2.6E-04	2.5E-07	2.43E-05
Nickel Compounds	2.1E-03	2.1E-06	1.96E-04
Selenium Compounds	2.4E-05	2.4E-08	2.24E-06
Organic Compounds			
1,1,2,2-Tetrachlorethane	Not Applicable	6.63E-05	6.31E-03
1,1,2-Trichloroethane		5.27E-05	5.02E-03
1,3-Butadiene		8.20E-04	7.81E-02
1,3-Dichloropropene		4.38E-04	4.17E-02
2,2,4-Trimethylpentane		8.46E-04	8.06E-02
Acetaldehyde		7.76E-03	7.39E-01
Acrolein		7.78E-03	7.41E-01
Benzene		1.94E-03	1.85E-01
Biphenyl		3.95E-06	3.76E-04
Carbon Tetrachloride		6.07E-05	5.78E-03
Chlorobenzene		4.44E-05	4.23E-03
Chloroform		4.71E-05	4.49E-03
Ethylbenzene		1.08E-04	1.03E-02
Ethylene Dibromide		7.34E-05	6.99E-03
Formaldehyde		5.52E-02	5.26E+00
Methanol		2.48E-03	2.36E-01
Methylene Chloride		1.47E-04	1.40E-02
n-Hexane		4.45E-04	4.24E-02
Naphthalene[1]		9.63E-05	9.17E-03
Phenol		4.21E-05	4.01E-03
Polycyclic Organic Matter (POM)[2]		3.23E-04	3.07E-02
Styrene		5.48E-05	5.22E-03
Toluene		9.63E-04	9.17E-02
Vinyl Chloride		2.47E-05	2.35E-03
Xylene		2.68E-04	2.55E-02
TOTAL[3]		8.00E-02	7.6

[1] Naphthalene is a HAP that is subject individually to the 10 tpy major source threshold, but that is also one of several polycyclic organic matter (POM) compounds that, in aggregate, are subject to the same 10 tpy major source threshold.

[2] See table below for list of individual polycyclic organic matter (POM) compounds. POM defines a broad class of compounds that generally includes all organic structures having two or more fused aromatic rings (i.e., rings that share a common border), and that have a boiling point greater than or equal to 212°F (100°C). See http://www.epa.gov/ttn/atw/hlthef/polycycl.html#ref11

[3] Because naphthalene is accounted for individually and in the calculation of POM EF, its contribution here is discounted so as to avoid double-counting.

Trace Metal Compounds EF Basis: AP-42, Table 1.4-4, July 1998.

EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-4.

Organic Compounds EF Basis: AP-42, Table 3.2-1, July 2000.

POM Compounds	EF (lb/MMBtu)
2-Methylnaphthalene*	2.14E-04
Acenaphthene*	1.33E-06
Acenaphthylene*	3.17E-06
Anthracene*	7.18E-07
Benzo(a)anthracene*	3.36E-07
Benzo(a)pyrene*	5.68E-09
Benzo(b)fluoranthene*	8.51E-09
Benzo(e)pyrene*	2.34E-08
Benzo(g,h,l)perylene*	2.48E-08
Benzo(k)fluoranthene*	4.26E-09
Chrysene*	6.72E-07
Fluoranthene*	3.61E-07
Fluorene*	1.69E-06
Indeno(1,2,3-cd)pyrene*	9.93E-09
Naphthalene*,**	9.63E-05
Perylene*	4.97E-09
Phenanthrene*	3.53E-06
Pyrene*	5.84E-07
SUBTOTAL	3.23E-04

EF Basis: AP-42, Table 3.2-1, July 2000.

* designates a polycyclic aromatic hydrocarbon (PAH). PAHs are potent atmospheric pollutants that consist of fused aromatic rings and do not contain heteroatoms or carry substituents. See http://en.wikipedia.org/wiki/Polycyclic_aromatic_hydrocarbon#PAH_compounds

** designates a POM compound that is also an individual HAP.

Non-HAP Potential to Emit

Emission Unit: **EU-5**
Description: Caterpillar 3408 Backup Electrical Power Generator
Reciprocating IC Compressor Engine, four-stroke, rich-burn, spark ignition
Control Device: none
Fuel: natural gas
Installation Date: 1998
Design Maximum Output Capacity: 400 horsepower
Design Maximum Heat Input Capcity: 3.76 MMBtu/hr
Operation: 500 hours per year[1]

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Monoxide (CO)	3.72	3.5	1
Lead (Pb)	4.90E-07	4.61E-07	2
Nitrogen Oxides (NO_X)	2.27	2.1	1
Particulate (PM)	0.0095	0.01	3
Inhalable Coarse Particulate (PM_{10})	0.01941	0.02	3
Fine Particulate ($PM_{2.5}$)	0.01941	0.02	3
Sulfur Dioxide (SO_2)	0.0544	0.1	4
Volatile Organic Compounds (VOC)	0.0296	0.03	1

NON-FUGITIVE EMISSIONS

Greenhouse Gas Emissions (CO_2 Equivalent)	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Dioxide (CO_2)	116.977	110.0	5
Methane (CH_4)	0.055	0.1	5
Nitrous Oxide (N_2O)	0.066	0.1	5
TOTAL		110	

[1] September 6, 1995 EPA memorandum entitled, "Calculating Potential to Emit (PTE) for Emergency Generators"

EF Reference	Description
1	Table 3.2-3 of AP-42, July 2000.
2	Table 1.4-2 of AP-42, July 1998. EF (lb/MMBtu) = (0.0005 lb/1x10^6 scf) X (1x10^6 scf/1020 MMBtu). See footnote a to Table 1.4-2.

EF Reference 3

Table 3.2-3 of AP-42, July 2000. Filterable PM (≤ 1μm) = 9.50x10^{-3} lb/MMBtu. Condensible PM ~ 9.91x10^{-3} lb/MMBtu. PM EF equal to filterable portion. PM_{10} and $PM_{2.5}$ EF equal to sum of both; 0.01941 lb/MMBtu. EPA did not employ the applicable FARR PM limit to calculate potential emissions because the resultant 0.1871 lb/MMBtu PM EF is unrealistic for a natural gas fired engine. The calculation to derive the 0.1871 lb/MMBtu PM EF is as follows:

Basis: FARR combustion source stack PM emission limit of 0.1 gr/dscf corrected to 7% O_2 at 40 CFR 49.125(d)(1)

EF (lb/MMBtu) = FARR PM Limit (gr/dscf@7%O_2) X $CF_{7\rightarrow0\%O2}$ X F_d (dscf/MMBtu) / $CF_{gr\rightarrow lb}$ (gr/lb)

• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR PM Calculated EF (lb/MMBtu)	FARR PM Emission Limit (gr/dscf @7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	F_d (dscf/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)
0.1871	0.1	1.504	8,710	7,000

EF Reference 4

Option 1: 0.0544 lb/MMBtu. This emission factor is employed to determine PTE as it limits emissions to less than Option 2 or 3 below.

Basis: FERC natural gas pipeline tariff sulfur limit of 20 gr/100 standard cubic feet.

EF (lb/MMBtu) = Pipeline tariff S Limit (gr/100 ft^3) / $CF_{100ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{gr\rightarrow lb}$ X $CF_{S\rightarrow SO2}$

• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.

• $CF_{ft3\rightarrow Btu}$ = 105000 Btu/100 ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

Pipeline Tariff Calculate SO_2 EF (lb/MMBtu)	Pipeline Tariff Fuel Sulfur Limit (gr/100 ft^3)	$CF_{ft3\rightarrow Btu}$ (Btu/100 ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.0544	20	105000	1.E+06	7000	2

Option 2: 0.1308 lb/MMBtu.

Basis: FARR gaseous fuel sulfur limit of 1.1 g/dry standard cubic meter at 40 CFR 49.130(d)(8)

EF (lb/MMBtu) = FARR Fuel S Limit (g/m^3) / $CF_{m3\rightarrow ft3}$ / $CF_{ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{g\rightarrow lb}$ X $CF_{S\rightarrow SO2}$

• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.

• $CF_{ft3\rightarrow Btu}$ = 1050 Btu/ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

FARR Fuel S Calculate SO_2 EF (lb/MMBtu)	FARR Fuel Sulfur Limit (g/m^3)	$CF_{m3\rightarrow ft3}$ (ft^3/m^3)	$CF_{ft3\rightarrow Btu}$ (Btu/ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{g\rightarrow lb}$ (g/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.1308	1.1	35.3147	1050	1.E+06	453.592	2

Option 3: 1.087 lb/MMBtu.

Basis: FARR combustion source stack SO_2 emission limit of 500 parts per million by volume dry basis (ppmvd) corrected to 7% O_2 at 40 CFR 49.129(d)(1)

EF (lb/MMBtu) = FARR SO_2 Limit (ppmvd@7%O_2) X $CF_{7\rightarrow0\%O2}$ X $CF_{ppm\rightarrow lb/dscfSO2}$ X F_d (dscf/MMBtu)

• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• $CF_{ppm\rightarrow lb/dscfSO2}$ = 1.660 X 10^{-7} lb SO_2/dscf / ppm SO_2. See Table 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR 500 ppm Calculate SO_2 EF (lb/MMBtu)	FARR SO_2 Emission Limit (ppmvd@7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	$CF_{ppm\rightarrow lb/dscfSO2}$ (lb/dscf / ppm)	F_d (dscf/MMBtu)
1.087	500	1.504	1.66E-07	8710

EF Reference 5

EPA's March 2011 guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" states that the GHG Report Rule (40 CFR 98), "should be considered a primary reference for sources and permitting authorities in estimating GHG emissions and establishing measurement techniques when preparing or processing permit applications." Therefore, GHG Reporting Rule emission factors will be employed to determine GHG PTE.

Carbon Dioxide (CO_2)

EF (lb CO_2e/MMBtu) = EF (kg CO_2/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CO2} (lb CO_2e/lb CO_2)

Calculated CO_2e EF for CO_2 (lb CO_2e/MMBtu)	40 CFR 98 Table C-1 EF (kg CO_2/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CO_2)
116.977	53.06	2.20462262	1

Methane (CH_4)

EF (lb CO_2e/MMBtu) = EF (kg CH_4/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CH4} (lb CO_2e/lb CH_4)

Calculated CO_2e EF for CH_4 (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg CH_4/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CH_4)
0.055	0.001	2.20462262	25

Nitrous Oxide (N_2O)

EF (lb CO_2e/MMBtu) = EF (kg N_2O/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{N2O} (lb CO_2e/lb N_2O)

Calculated CO_2e EF for N_2O (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg N_2O/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb N_2O)
0.066	0.0001	2.20462262	298

HAP Potential to Emit

Emission Unit:	**EU-5**
Description:	Caterpillar 3408 Backup Electrical Power Generator Reciprocating IC Compressor Engine, four-stroke, rich-burn, spark ignition
Control Device:	none
Fuel:	natural gas
Installation Date:	1998
Design Maximum Output Capacity:	400 horsepower
Design Maximum Heat Input Capcity:	3.76 MMBtu/hr
Operation:	500 hours per year[1]

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)
Trace Metal Compounds			
Arsenic Compounds	2.0E-04	2.0E-07	1.84E-07
Beryllium Compounds	1.2E-05	1.2E-08	1.11E-08
Cadmium Compounds	1.1E-03	1.1E-06	1.01E-06
Chromium Compounds (including hexavalent)	1.4E-03	1.4E-06	1.29E-06
Cobalt Compounds	8.4E-05	8.2E-08	7.74E-08
Manganese Compounds	3.8E-04	3.7E-07	3.50E-07
Mercury Compounds	2.6E-04	2.5E-07	2.40E-07
Nickel Compounds	2.1E-03	2.1E-06	1.94E-06
Selenium Compounds	2.4E-05	2.4E-08	2.21E-08
Organic Compounds			
1,1,2,2-Tetrachlorethane	Not Applicable	2.53E-05	2.38E-05
1,1,2-Trichloroethane		1.53E-04	1.44E-04
1,3-Butadiene		6.63E-04	6.23E-04
1,3-Dichloropropene		1.27E-05	1.19E-05
Acetaldehyde		2.79E-03	2.62E-03
Acrolein		2.63E-03	2.47E-03
Benzene		1.58E-03	1.49E-03
Carbon Tetrachloride		1.77E-05	1.66E-05
Chlorobenzene		1.29E-05	1.21E-05
Chloroform		1.37E-05	1.29E-05
Ethylbenzene		2.48E-05	2.33E-05
Ethylene Dibromide		2.13E-05	2.00E-05
Formaldehyde		2.05E-02	1.93E-02
Methanol		3.06E-03	2.88E-03
Methylene Chloride		4.12E-05	3.87E-05
Naphthalene[2]		9.71E-05	9.13E-05
Polycyclic Organic Matter (POM)[3]		1.41E-04	1.33E-04
Styrene		1.19E-05	1.12E-05
Toluene		5.58E-04	5.25E-04
Vinyl Chloride		7.18E-06	6.75E-06
Xylene		1.95E-04	1.83E-04
TOTAL[4]		3.25E-02	3.05E-02

[1] September 6, 1995 EPA memorandum entitled, "Calculating Potential to Emit (PTE) for Emergency Generators"

[2] Naphthalene is a HAP that is subject individually to the 10 tpy major source threshold, but that is also one of several polycyclic organic matter (POM) compounds that, in aggregate, are subject to the same 10 tpy major source threshold.

[3] POM defines a broad class of compounds that generally includes all organic structures having two or more fused aromatic rings (i.e., rings that share a common border), and that have a boiling point greater than or equal to 212°F (100°C). See http://www.epa.gov/ttn/atw/hlthef/polycycl.html#ref11

[4] Because naphthalene is accounted for individually and in the calculation of POM EF, its contribution here is discounted so as to avoid double-counting.

Trace Metal Compounds EF Basis: AP-42, Table 1.4-4, July 1998.
EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-4.

Organic Compounds EF Basis: AP-42, Table 3.2-3, July 2000.

Non-HAP Potential to Emit

Emission Unit: **EU-6**
Description: Sellers Model C80W Boiler
Boiler provides glycol heat to keep compressor engines on warm standby
Control Device: none
Fuel: natural gas
Installation Date: 1989
Design Maximum Heat Input Capcity: 3.5154 MMBtu/hr
Operation: 8760 hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Monoxide (CO)	84	0.0824	1.3	1
Lead (Pb)	0.0005	4.9E-07	7.55E-06	2
Nitrogen Oxides (NO_X)	100	0.0980	1.5	1
Particulate (PM)	1.9	0.0019	0.03	3
Inhalable Coarse Particulate (PM_{10})	7.6	0.0075	0.11	3
Fine Particulate ($PM_{2.5}$)	7.6	0.0075	0.11	3
Sulfur Dioxide (SO_2)	Not Applicable	0.0544	0.8	4
Volatile Organic Compounds (VOC)	5.5	0.0054	0.08	2

NON-FUGITIVE EMISSIONS

Greenhouse Gas Emissions (CO_2 Equivalent)	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Dioxide (CO_2)	Not Applicable	116.977	1801.2	5
Methane (CH_4)		0.055	0.8	5
Nitrous Oxide (N_2O)		0.066	1.0	5
TOTAL			1,803	

<table>
<tr><th>EF Reference</th><th>Description</th></tr>
<tr><td>1</td><td>Table 1.4-1 of AP-42, July 1998. EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-1.</td></tr>
<tr><td>2</td><td>Table 1.4-2 of AP-42, July 1998. EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-2.</td></tr>
<tr><td>3</td><td>
Table 1.4-2 of AP-42, July 1998. Filterable PM (≤ 1μm) = 1.9 $lb/1x10^6$ scf. Condensible PM ~ 5.7 $lb/1x10^6$ scf. PM EF equal to filterable portion. PM_{10} and $PM_{2.5}$ EF equal to sum of both; 7.6 $lb/1x10^6$ scf. EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-2.
EPA did not employ the applicable FARR PM limit to calculate potential emissions because the resultant 0.1871 lb/MMBtu PM EF is unrealistic for a natural gas fired boiler. The calculation to derive the 0.1871 lb/MMBtu PM EF is as follows:
Basis: FARR combustion source stack PM emission limit of 0.1 gr/dscf corrected to 7% O_2 at 40 CFR 49.125(d)(1)
EF (lb/MMBtu) = FARR PM Limit (gr/dscf@7%O_2) X $CF_{7\rightarrow0\%O2}$ X F_d (dscf/MMBtu) / $CF_{gr\rightarrow lb}$ (gr/lb)
• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.
• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.
<table>
<tr><th>FARR PM Calculated EF (lb/MMBtu)</th><th>FARR PM Emission Limit (gr/dscf @7%O_2)</th><th>$CF_{7\rightarrow0\%O2}$ (unitless)</th><th>F_d (dscf/MMBtu)</th><th>$CF_{gr\rightarrow lb}$ (gr/lb)</th></tr>
<tr><td>0.1871</td><td>0.1</td><td>1.504</td><td>8,710</td><td>7,000</td></tr>
</table>
</td></tr>
<tr><td>4</td><td>
<u>Option 1</u>: 0.0544 lb/MMBtu. This emission factor is employed to determine PTE as it limits emissions to less than Option 2 or 3 below.
Basis: FERC natural gas pipeline tariff sulfur limit of 20 gr/100 standard cubic feet.
EF (lb/MMBtu) = Pipeline tariff S Limit (gr/100 ft^3) / $CF_{100ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{gr\rightarrow lb}$ X $CF_{S\rightarrow SO2}$
• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.
• $CF_{ft3\rightarrow Btu}$ = 105000 Btu/100 ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.
<table>
<tr><th>Pipeline Tariff Calculate SO_2 EF (lb/MMBtu)</th><th>Pipeline Tariff Fuel Sulfur Limit (gr/100 ft^3)</th><th>$CF_{ft3\rightarrow Btu}$ (Btu/100 ft^3)</th><th>$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)</th><th>$CF_{gr\rightarrow lb}$ (gr/lb)</th><th>$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)</th></tr>
<tr><td>0.0544</td><td>20</td><td>105000</td><td>1.E+06</td><td>7000</td><td>2</td></tr>
</table>
<u>Option 2</u>: 0.1308 lb/MMBtu.
Basis: FARR gaseous fuel sulfur limit of 1.1 g/dry standard cubic meter at 40 CFR 49.130(d)(8)
EF (lb/MMBtu) = FARR Fuel S Limit (g/m^3) / $CF_{m3\rightarrow ft3}$ / $CF_{ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{g\rightarrow lb}$ X $CF_{S\rightarrow SO2}$
• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.
• $CF_{ft3\rightarrow Btu}$ = 1050 Btu/ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.
<table>
<tr><th>FARR Fuel S Calculate SO_2 EF (lb/MMBtu)</th><th>FARR Fuel Sulfur Limit (g/m^3)</th><th>$CF_{m3\rightarrow ft3}$ (ft^3/m^3)</th><th>$CF_{ft3\rightarrow Btu}$ (Btu/ft^3)</th><th>$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)</th><th>$CF_{g\rightarrow lb}$ (g/lb)</th><th>$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)</th></tr>
<tr><td>0.1308</td><td>1.1</td><td>35.3147</td><td>1050</td><td>1.E+06</td><td>453.592</td><td>2</td></tr>
</table>
<u>Option 3</u>: 1.087 lb/MMBtu.
Basis: FARR combustion source stack SO_2 emission limit of 500 parts per million by volume dry basis (ppmvd) corrected to 7% O_2 at 40 CFR 49.129(d)(1)
EF (lb/MMBtu) = FARR SO_2 Limit (ppmvd@7%O_2) X $CF_{7\rightarrow0\%O2}$ X $CF_{ppm\rightarrow lb/dscfSO2}$ X F_d (dscf/MMBtu)
• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.
• $CF_{ppm\rightarrow lb/dscfSO2}$ = 1.660 X 10^{-7} lb SO_2/dscf / ppm SO_2. See Table 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.
• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.
<table>
<tr><th>FARR 500 ppm Calculate SO_2 EF (lb/MMBtu)</th><th>FARR SO_2 Emission Limit (ppmvd@7%O_2)</th><th>$CF_{7\rightarrow0\%O2}$ (unitless)</th><th>$CF_{ppm\rightarrow lb/dscfSO2}$ (lb/dscf / ppm)</th><th>F_d (dscf/MMBtu)</th></tr>
<tr><td>1.087</td><td>500</td><td>1.504</td><td>1.66E-07</td><td>8710</td></tr>
</table>
</td></tr>
<tr><td>5</td><td>
EPA's March 2011 guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" states that the GHG Report Rule (40 CFR 98), "should be considered a primary reference for sources and permitting authorities in estimating GHG emissions and establishing measurement techniques when preparing or processing permit applications." Therefore, GHG Reporting Rule emission factors will be employed to determine GHG PTE.
<u>Carbon Dioxide (CO_2)</u>
EF (lb CO_2e/MMBtu) = EF (kg CO_2/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CO2} (lb CO_2e/lb CO_2)
<table>
<tr><th>Calculated CO_2e EF for CO_2 (lb CO_2e/MMBtu)</th><th>40 CFR 98 Table C-1 EF (kg CO_2/MMBtu)</th><th>$CF_{kg\rightarrow lb}$ (lb/kg)</th><th>40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CO_2)</th></tr>
<tr><td>116.977</td><td>53.06</td><td>2.20462262</td><td>1</td></tr>
</table>
<u>Methane (CH_4)</u>
EF (lb CO_2e/MMBtu) = EF (kg CH_4/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CH4} (lb CO_2e/lb CH_4)
<table>
<tr><th>Calculated CO_2e EF for CH_4 (lb CO_2e/hp-hr)</th><th>40 CFR 98 Table C-2 EF (kg CH_4/MMBtu)</th><th>$CF_{kg\rightarrow lb}$ (lb/kg)</th><th>40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CH_4)</th></tr>
<tr><td>0.055</td><td>0.001</td><td>2.20462262</td><td>25</td></tr>
</table>
<u>Nitrous Oxide (N_2O)</u>
EF (lb CO_2e/MMBtu) = EF (kg N_2O/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{N2O} (lb CO_2e/lb N_2O)
<table>
<tr><th>Calculated CO_2e EF for N_2O (lb CO_2e/hp-hr)</th><th>40 CFR 98 Table C-2 EF (kg N_2O/MMBtu)</th><th>$CF_{kg\rightarrow lb}$ (lb/kg)</th><th>40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb N_2O)</th></tr>
<tr><td>0.066</td><td>0.0001</td><td>2.20462262</td><td>298</td></tr>
</table>
</td></tr>
</table>

HAP Potential to Emit

Emission Unit:	**EU-6**
Description:	Sellers Model C80W Boiler
	Boiler provides glycol heat to keep compressor engines on warm standby
Control Device:	none
Fuel:	natural gas
Installation Date:	1989
Design Maximum Heat Input Capcity:	3.5154 MMBtu/hr
Operation:	8760 hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)
Trace Metal Compounds			
Arsenic Compounds	2.0E-04	2.0E-07	3.02E-06
Beryllium Compounds	1.2E-05	1.2E-08	1.81E-07
Cadmium Compounds	1.1E-03	1.1E-06	1.66E-05
Chromium Compounds (including hexavalent)	1.4E-03	1.4E-06	2.11E-05
Cobalt Compounds	8.4E-05	8.2E-08	1.27E-06
Manganese Compounds	3.8E-04	3.7E-07	5.74E-06
Mercury Compounds	2.6E-04	2.5E-07	3.92E-06
Nickel Compounds	2.1E-03	2.1E-06	3.17E-05
Selenium Compounds	2.4E-05	2.4E-08	3.62E-07
Organic Compounds			
Benzene	2.1E-03	2.1E-06	3.17E-05
Dichlorobenzene	1.2E-03	1.2E-06	1.81E-05
Formaldehyde	7.5E-02	7.4E-05	1.13E-03
Hexane	1.8E+00	1.8E-03	2.72E-02
Naphthalene[1]	6.1E-04	6.0E-07	9.21E-06
Polycyclic Organic Matter (POM)[2]	7.0E-04	6.8E-07	1.05E-05
Toluene	3.4E-03	3.3E-06	5.13E-05
TOTAL[3]	1.89E+00	1.85E-03	2.85E-02

[1] Naphthalene is a HAP that is subject individually to the 10 tpy major source threshold, but that is also one of several polycyclic organic matter (POM) compounds that, in aggregate, are subject to the same 10 tpy major source threshold.

[2] POM defines a broad class of compounds that generally includes all organic structures having two or more fused aromatic rings (i.e., rings that share a common border), and that have a boiling point greater than or equal to 212°F (100°C). See http://www.epa.gov/ttn/atw/hlthef/polycycl.html#ref11

[3] Because naphthalene is accounted for individually and in the calculation of POM EF, its contribution here is discounted so as to avoid double-counting.

Trace Metal Compounds EF Basis: AP-42, Table 1.4-4, July 1998.

EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-4.

Organic Compound EF Basis: AP-42, Table 1.4-3, July 1998.

POM Compounds	EF ($lb/10^6$ scf)	EF (lb/MMBtu)
2-Methylnaphthalene*	2.4E-05	2.4E-08
3-Methychloranthrene*	1.8E-06	1.8E-09
7,12-Dimethylbenz(a)anthracene*	1.6E-05	1.6E-08
Acenaphthene*	1.8E-06	1.8E-09
Acenaphthylene*	1.8E-06	1.8E-09
Anthracene*	2.4E-06	2.4E-09
Benzo(a)anthracene*	1.8E-06	1.8E-09
Benzo(a)pyrene*	1.2E-06	1.2E-09
Benzo(b)fluoranthene*	1.8E-06	1.8E-09
Benzo(g,h,l)perylene*	1.2E-06	1.2E-09
Benzo(k)fluoranthene*	1.8E-06	1.8E-09
Chrysene*	1.8E-06	1.8E-09
Dibenzo(a,h)anthracene*	1.2E-06	1.2E-09
Fluoranthene*	3.0E-06	2.9E-09
Fluorene*	2.8E-06	2.7E-09
Indeno(1,2,3-cd)pyrene*	1.8E-06	1.8E-09
Naphthalene*,**	6.1E-04	6.0E-07
Phenanthrene*	1.7E-05	1.7E-08
Pyrene*	5.0E-06	4.9E-09
SUBTOTAL	7.0E-04	6.8E-07

* designates a polycyclic aromatic hydrocarbon (PAH). PAHs are potent atmospheric pollutants that consist of fused aromatic rings and do not contain heteroatoms
** designates a POM compound that is also an individual HAP.

Non-HAP Potential to Emit

Emission Unit: **EU-7**
Description: BS&B Model IH-3012-500M-T2 Heater (Refurbished)
Boiler provides glycol heat to keep compressor engines on warm standby
Control Device: none
Fuel: natural gas
Installation Date: ?
Design Maximum Heat Input Capcity: 0.50 MMBtu/hr
Operation: 8760 hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Monoxide (CO)	84	0.0824	0.2	1
Lead (Pb)	0.0005	4.9E-07	1.07E-06	2
Nitrogen Oxides (NO_X)	100	0.0980	0.2	1
Particulate (PM)	1.9	0.0019	0.00	3
Inhalable Coarse Particulate (PM_{10})	7.6	0.0075	0.02	3
Fine Particulate ($PM_{2.5}$)	7.6	0.0075	0.02	3
Sulfur Dioxide (SO_2)	Not Applicable	0.0544	0.1	4
Volatile Organic Compounds (VOC)	5.5	0.0054	0.01	2

NON-FUGITIVE EMISSIONS

Greenhouse Gas Emissions (CO_2 Equivalent)	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Dioxide (CO_2)	Not Applicable	116.977	256.2	5
Methane (CH_4)		0.055	0.1	5
Nitrous Oxide (N_2O)		0.066	0.1	5
TOTAL			256	

EF Reference	Description
1	Table 1.4-1 of AP-42, July 1998. EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-1.
2	Table 1.4-2 of AP-42, July 1998. EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-2.

EF Reference 3

Table 1.4-2 of AP-42, July 1998. Filterable PM (≤ 1μm) = 1.9 $lb/1x10^6$ scf. Condensible PM ~ 5.7 $lb/1x10^6$ scf. PM EF equal to filterable portion. PM_{10} and $PM_{2.5}$ EF equal to sum of both; 7.6 $lb/1x10^6$ scf. EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-2.

EPA did not employ the applicable FARR PM limit to calculate potential emissions because the resultant 0.1871 lb/MMBtu PM EF is unrealistic for a natural gas fired boiler. The calculation to derive the 0.1871 lb/MMBtu PM EF is as follows:

Basis: FARR combustion source stack PM emission limit of 0.1 gr/dscf corrected to 7% O_2 at 40 CFR 49.125(d)(1)

EF (lb/MMBtu) = FARR PM Limit (gr/dscf@7%O_2) X $CF_{7\rightarrow0\%O2}$ X F_d (dscf/MMBtu) / $CF_{gr\rightarrow lb}$ (gr/lb)

• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR PM Calculated EF (lb/MMBtu)	FARR PM Emission Limit (gr/dscf @7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	F_d (dscf/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)
0.1871	0.1	1.504	8,710	7,000

EF Reference 4

Option 1: 0.0544 lb/MMBtu. This emission factor is employed to determine PTE as it limits emissions to less than Option 2 or 3 below.

Basis: FERC natural gas pipeline tariff sulfur limit of 20 gr/100 standard cubic feet.

EF (lb/MMBtu) = Pipeline tariff S Limit (gr/100 ft^3) / $CF_{100ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{gr\rightarrow lb}$ X $CF_{S\rightarrow SO2}$

• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.

• $CF_{ft3\rightarrow Btu}$ = 105000 Btu/100 ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

Pipeline Tariff Calculate SO_2 EF (lb/MMBtu)	Pipeline Tariff Fuel Sulfur Limit (gr/100 ft^3)	$CF_{ft3\rightarrow Btu}$ (Btu/100 ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.0544	20	105000	1.E+06	7000	2

Option 2: 0.1308 lb/MMBtu.

Basis: FARR gaseous fuel sulfur limit of 1.1 g/dry standard cubic meter at 40 CFR 49.130(d)(8)

EF (lb/MMBtu) = FARR Fuel S Limit (g/m^3) / $CF_{m3\rightarrow ft3}$ / $CF_{ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{g\rightarrow lb}$ X $CF_{S\rightarrow SO2}$

• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.

• $CF_{ft3\rightarrow Btu}$ = 1050 Btu/ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

FARR Fuel S Calculate SO_2 EF (lb/MMBtu)	FARR Fuel Sulfur Limit (g/m^3)	$CF_{m3\rightarrow ft3}$ (ft^3/m^3)	$CF_{ft3\rightarrow Btu}$ (Btu/ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{g\rightarrow lb}$ (g/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.1308	1.1	35.3147	1050	1.E+06	453.592	2

Option 3: 1.087 lb/MMBtu.

Basis: FARR combustion source stack SO_2 emission limit of 500 parts per million by volume dry basis (ppmvd) corrected to 7% O_2 at 40 CFR 49.129(d)(1)

EF (lb/MMBtu) = FARR SO_2 Limit (ppmvd@7%O_2) X $CF_{7\rightarrow0\%O2}$ X $CF_{ppm\rightarrow lb/dscfSO2}$ X F_d (dscf/MMBtu)

• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• $CF_{ppm\rightarrow lb/dscfSO2}$ = 1.660 X 10^{-7} lb SO_2/dscf / ppm SO_2. See Table 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR 500 ppm Calculate SO_2 EF (lb/MMBtu)	FARR SO_2 Emission Limit (ppmvd@7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	$CF_{ppm\rightarrow lb/dscfSO2}$ (lb/dscf / ppm)	F_d (dscf/MMBtu)
1.087	500	1.504	1.66E-07	8710

EF Reference 5

EPA's March 2011 guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" states that the GHG Report Rule (40 CFR 98), "should be considered a primary reference for sources and permitting authorities in estimating GHG emissions and establishing measurement techniques when preparing or processing permit applications." Therefore, GHG Reporting Rule emission factors will be employed to determine GHG PTE.

Carbon Dioxide (CO_2)

EF (lb CO_2e/MMBtu) = EF (kg CO_2/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CO2} (lb CO_2e/lb CO_2)

Calculated CO_2e EF for CO_2 (lb CO_2e/MMBtu)	40 CFR 98 Table C-1 EF (kg CO_2/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CO_2)
116.977	53.06	2.20462262	1

Methane (CH_4)

EF (lb CO_2e/MMBtu) = EF (kg CH_4/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CH4} (lb CO_2e/lb CH_4)

Calculated CO_2e EF for CH_4 (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg CH_4/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CH_4)
0.055	0.001	2.20462262	25

Nitrous Oxide (N_2O)

EF (lb CO_2e/MMBtu) = EF (kg N_2O/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{N2O} (lb CO_2e/lb N_2O)

Calculated CO_2e EF for N_2O (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg N_2O/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb N_2O)
0.066	0.0001	2.20462262	298

HAP Potential to Emit

Emission Unit: **EU-7**
Description: BS&B Model IH-3012-500M-T2 Heater (Refurbished)
Boiler provides glycol heat to keep compressor engines on warm standby
Control Device: none
Fuel: natural gas
Installation Date: ?
Design Maximum Heat Input Capcity: 0.50 MMBtu/hr
Operation: 8760 hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)
Trace Metal Compounds			
Arsenic Compounds	2.0E-04	2.0E-07	4.29E-07
Beryllium Compounds	1.2E-05	1.2E-08	2.58E-08
Cadmium Compounds	1.1E-03	1.1E-06	2.36E-06
Chromium Compounds (including hexavalent)	1.4E-03	1.4E-06	3.01E-06
Cobalt Compounds	8.4E-05	8.2E-08	1.80E-07
Manganese Compounds	3.8E-04	3.7E-07	8.16E-07
Mercury Compounds	2.6E-04	2.5E-07	5.58E-07
Nickel Compounds	2.1E-03	2.1E-06	4.51E-06
Selenium Compounds	2.4E-05	2.4E-08	5.15E-08
Organic Compounds			
Benzene	2.1E-03	2.1E-06	4.51E-06
Dichlorobenzene	1.2E-03	1.2E-06	2.58E-06
Formaldehyde	7.5E-02	7.4E-05	1.61E-04
Hexane	1.8E+00	1.8E-03	3.86E-03
Naphthalene[1]	6.1E-04	6.0E-07	1.31E-06
Polycyclic Organic Matter (POM)[2]	7.0E-04	6.8E-07	1.50E-06
Toluene	3.4E-03	3.3E-06	7.30E-06
TOTAL[3]	1.89E+00	1.85E-03	4.05E-03

[1] Naphthalene is a HAP that is subject individually to the 10 tpy major source threshold, but that is also one of several polycyclic organic matter (POM) compounds that, in aggregate, are subject to the same 10 tpy major source threshold.

[2] POM defines a broad class of compounds that generally includes all organic structures having two or more fused aromatic rings (i.e., rings that share a common border), and that have a boiling point greater than or equal to 212°F (100°C). See http://www.epa.gov/ttn/atw/hlthef/polycycl.html#ref11

[3] Because naphthalene is accounted for individually and in the calculation of POM EF, its contribution here is discounted so as to avoid double-counting.

<u>Trace Metal Compounds EF Basis: AP-42, Table 1.4-4, July 1998.</u>

EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-4.

<u>Organic Compound EF Basis: AP-42, Table 1.4-3, July 1998.</u>

POM Compounds	EF ($lb/10^6$ scf)	EF (lb/MMBtu)
2-Methylnaphthalene*	2.4E-05	2.4E-08
3-Methychloranthrene*	1.8E-06	1.8E-09
7,12-Dimethylbenz(a)anthracene*	1.6E-05	1.6E-08
Acenaphthene*	1.8E-06	1.8E-09
Acenaphthylene*	1.8E-06	1.8E-09
Anthracene*	2.4E-06	2.4E-09
Benzo(a)anthracene*	1.8E-06	1.8E-09
Benzo(a)pyrene*	1.2E-06	1.2E-09
Benzo(b)fluoranthene*	1.8E-06	1.8E-09
Benzo(g,h,l)perylene*	1.2E-06	1.2E-09
Benzo(k)fluoranthene*	1.8E-06	1.8E-09
Chrysene*	1.8E-06	1.8E-09
Dibenzo(a,h)anthracene*	1.2E-06	1.2E-09
Fluoranthene*	3.0E-06	2.9E-09
Fluorene*	2.8E-06	2.7E-09
Indeno(1,2,3-cd)pyrene*	1.8E-06	1.8E-09
Naphthalene*,**	6.1E-04	6.0E-07
Phenanthrene*	1.7E-05	1.7E-08
Pyrene*	5.0E-06	4.9E-09
SUBTOTAL	7.0E-04	6.8E-07

* designates a polycyclic aromatic hydrocarbon (PAH). PAHs are potent atmospheric pollutants that consist of fused aromatic rings and do not contain heteroatoms
** designates a POM compound that is also an individual HAP.

Non-HAP Potential to Emit

Emission Unit: **EU-8**
Description: Heaters and Furnaces
Control Device: none
Fuel: natural gas

Equipment List	Rated Capacity (MMBtu/hr)	
Shop Heater	0.25	
Shop Heater	0.25	
Breakroom Furnace	0.08	
Old Office Furnace	0.07	
Warehouse Shop Heater	0.16	
Auxilary Room Heater	0.3691	
Total	1.1791	MMBtu/hr
Operation:	8760	hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Monoxide (CO)	40	0.0824	0.4	1
Lead (Pb)	0.0005	4.90E-07	2.5E-06	2
Nitrogen Oxides (NO_X)	94	0.0980	0.5	1
Particulate (PM)	1.9	0.00186	0.01	3
Inhalable Coarse Particulate (PM_{10})	7.6	0.00745	0.04	3
Fine Particulate ($PM_{2.5}$)	7.6	0.00745	0.04	3
Sulfur Dioxide (SO_2)	Not Applicable	0.0544	0.3	4
Volatile Organic Compounds (VOC)	5.5	0.0054	0.03	2

NON-FUGITIVE EMISSIONS

Greenhouse Gas Emissions (CO_2 Equivalent)	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Dioxide (CO_2)	Not Applicable	116.977	604.1	5
Methane (CH_4)		0.055	0.3	5
Nitrous Oxide (N_2O)		0.066	0.3	5
TOTAL			605	

EF Reference	Description
1	Table 1.4-1 of AP-42, July 1998. EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-1.
2	Table 1.4-2 of AP-42, July 1998. EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-2.

3

Table 1.4-2 of AP-42, July 1998. Filterable PM (≤ 1μm) = 1.9 $lb/1x10^6$ scf. Condensible PM ~ 5.7 $lb/1x10^6$ scf. PM EF equal to filterable portion. PM_{10} and $PM_{2.5}$ EF equal to sum of both; 7.6 $lb/1x10^6$ scf. EF (lb/MMBtu) = EF ($lb/1x10^6$ scf) X ($1x10^6$ scf/1020 MMBtu). See footnote a to Table 1.4-2.

EPA did not employ the applicable FARR PM limit to calculate potential emissions because the resultant 0.1871 lb/MMBtu PM EF is unrealistic for a natural gas fired boiler. The calculation to derive the 0.1871 lb/MMBtu PM EF is as follows:

Basis: FARR combustion source stack PM emission limit of 0.1 gr/dscf corrected to 7% O_2 at 40 CFR 49.125(d)(1)

EF (lb/MMBtu) = FARR PM Limit (gr/dscf@7%O_2) X $CF_{7\rightarrow0\%O2}$ X F_d (dscf/MMBtu) / $CF_{gr\rightarrow lb}$ (gr/lb)

• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR PM Calculated EF (lb/MMBtu)	FARR PM Emission Limit (gr/dscf @7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	F_d (dscf/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)
0.1871	0.1	1.504	8,710	7,000

4

<u>Option 1</u>: 0.0544 lb/MMBtu. This emission factor is employed to determine PTE as it limits emissions to less than Option 2 or 3 below.

Basis: FERC natural gas pipeline tariff sulfur limit of 20 gr/100 standard cubic feet.

EF (lb/MMBtu) = Pipeline tariff S Limit (gr/100 ft^3) / $CF_{100ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{gr\rightarrow lb}$ X $CF_{S\rightarrow SO2}$

• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.

• $CF_{ft3\rightarrow Btu}$ = 105000 Btu/100 ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

Pipeline Tariff Calculate SO_2 EF (lb/MMBtu)	Pipeline Tariff Fuel Sulfur Limit (gr/100 ft^3)	$CF_{ft3\rightarrow Btu}$ (Btu/100 ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.0544	20	105000	1.E+06	7000	2

<u>Option 2</u>: 0.1308 lb/MMBtu.

Basis: FARR gaseous fuel sulfur limit of 1.1 g/dry standard cubic meter at 40 CFR 49.130(d)(8)

EF (lb/MMBtu) = FARR Fuel S Limit (g/m^3) / $CF_{m3\rightarrow ft3}$ / $CF_{ft3\rightarrow Btu}$ X $CF_{Btu\rightarrow MMBtu}$ / $CF_{g\rightarrow lb}$ X $CF_{S\rightarrow SO2}$

• $CF_{S\rightarrow SO2}$ = 2 lb SO_2/lb S. S + O_2 → SO_2. For every 1 mol S (16 lb/lb-mol) reactant, there is 1 mol SO_2 (32 lb/lb-mol) product. 32 / 16 = 2.

• $CF_{ft3\rightarrow Btu}$ = 1050 Btu/ft^3 fuel. See heating value of natural gas on page A-5 of Appendix A to AP-42, September 1985.

FARR Fuel S Calculate SO_2 EF (lb/MMBtu)	FARR Fuel Sulfur Limit (g/m^3)	$CF_{m3\rightarrow ft3}$ (ft^3/m^3)	$CF_{ft3\rightarrow Btu}$ (Btu/ft^3)	$CF_{Btu\rightarrow MMBtu}$ (Btu/MMBtu)	$CF_{g\rightarrow lb}$ (g/lb)	$CF_{S\rightarrow SO2}$ (lb SO_2/lb S)
0.1308	1.1	35.3147	1050	1.E+06	453.592	2

<u>Option 3</u>: 1.087 lb/MMBtu.

Basis: FARR combustion source stack SO_2 emission limit of 500 parts per million by volume dry basis (ppmvd) corrected to 7% O_2 at 40 CFR 49.129(d)(1)

EF (lb/MMBtu) = FARR SO_2 Limit (ppmvd@7%O_2) X $CF_{7\rightarrow0\%O2}$ X $CF_{ppm\rightarrow lb/dscfSO2}$ X F_d (dscf/MMBtu)

• $CF_{7\rightarrow0\%O2}$ = (20.9 - X_{O2Fd}) / (20.9 - X_{O2FARR}). To create a correction factor that adjusts the basis of the FARR emission limit from 7% O_2 to 0% O_2 (the basis for F_d), X_{O2Fd} = 0 and X_{O2FARR} = 7. The value 20.9 is the percent by volume of the ambient air that is O_2. Decreasing the O_2 from the FARR baseline increases the pollutant concentration. See Equation 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• $CF_{ppm\rightarrow lb/dscfSO2}$ = 1.660 X 10^{-7} lb SO_2/dscf / ppm SO_2. See Table 19-1 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

• F_d = 8,710 dscf/MMBtu for combustion of natural gas. See Table 19-2 of EPA Method 19 at Appendix A-7 to 40 CFR Part 60.

FARR 500 ppm Calculate SO_2 EF (lb/MMBtu)	FARR SO_2 Emission Limit (ppmvd@7%O_2)	$CF_{7\rightarrow0\%O2}$ (unitless)	$CF_{ppm\rightarrow lb/dscfSO2}$ (lb/dscf / ppm)	F_d (dscf/MMBtu)
1.087	500	1.504	1.66E-07	8710

5

EPA's March 2011 guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" states that the GHG Report Rule (40 CFR 98), "should be

<u>Carbon Dioxide (CO_2)</u>

EF (lb CO_2e/MMBtu) = EF (kg CO_2/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CO2} (lb CO_2e/lb CO_2)

Calculated CO_2e EF for CO_2 (lb CO_2e/MMBtu)	40 CFR 98 Table C-1 EF (kg CO_2/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CO_2)
116.977	53.06	2.20462262	1

<u>Methane (CH_4)</u>

EF (lb CO_2e/MMBtu) = EF (kg CH_4/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{CH4} (lb CO_2e/lb CH_4)

Calculated CO_2e EF for CH_4 (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg CH_4/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CH_4)
0.055	0.001	2.20462262	25

<u>Nitrous Oxide (N_2O)</u>

EF (lb CO_2e/MMBtu) = EF (kg N_2O/MMBtu) X $CF_{kg\rightarrow lb}$ (lb/kg) X GWP_{N2O} (lb CO_2e/lb N_2O)

Calculated CO_2e EF for N_2O (lb CO_2e/hp-hr)	40 CFR 98 Table C-2 EF (kg N_2O/MMBtu)	$CF_{kg\rightarrow lb}$ (lb/kg)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb N_2O)
0.066	0.0001	2.20462262	298

HAP Potential to Emit

Emission Unit: **EU-8**
Description: Heaters and Furnaces
Control Device: none
Fuel: natural gas

Equipment List	Rated Capacity (MMBtu/hr)	
Shop Heater	0.25	
Shop Heater	0.25	
Breakroom Furnace	0.08	
Old Office Furnace	0.07	
Warehouse Shop Heater	0.16	
Auxilary Room Heater	0.3691	
Total	1.1791	MMBtu/hr
Operation:	8760	hours per year

NON-FUGITIVE EMISSIONS

Criteria Pollutant Emissions	EF (lb/1x10^6 scf)	EF (lb/MMBtu)	PTE (tpy)
Trace Metal Compounds			
Arsenic Compounds	2.0E-04	2.0E-07	1.01E-06
Beryllium Compounds	1.2E-05	1.2E-08	6.08E-08
Cadmium Compounds	1.1E-03	1.1E-06	5.57E-06
Chromium Compounds (including hexavalent)	1.4E-03	1.4E-06	7.09E-06
Cobalt Compounds	8.4E-05	8.2E-08	4.25E-07
Manganese Compounds	3.8E-04	3.7E-07	1.92E-06
Mercury Compounds	2.6E-04	2.5E-07	1.32E-06
Nickel Compounds	2.1E-03	2.1E-06	1.06E-05
Selenium Compounds	2.4E-05	2.4E-08	1.22E-07
Organic Compounds			
Benzene	2.1E-03	2.1E-06	1.06E-05
Dichlorobenzene	1.2E-03	1.2E-06	6.08E-06
Formaldehyde	7.5E-02	7.4E-05	3.80E-04
Hexane	1.8E+00	1.8E-03	9.11E-03
Naphthalene[1]	6.1E-04	6.0E-07	3.09E-06
Polycyclic Organic Matter (POM)[2]	7.0E-04	6.8E-07	3.54E-06
Toluene	3.4E-03	3.3E-06	1.72E-05
TOTAL[3]	1.89E+00	1.85E-03	9.56E-03

[1] Naphthalene is a HAP that is subject individually to the 10 tpy major source threshold, but that is also one of several polycyclic organic matter (POM) compounds that, in aggregate, are subject to the same 10 tpy major source threshold.

[2] POM defines a broad class of compounds that generally includes all organic structures having two or more fused aromatic rings (i.e., rings that share a common border), and that have a boiling point greater than or equal to 212°F (100°C). See http://www.epa.gov/ttn/atw/hlthef/polycycl.html#ref11

[3] Because naphthalene is accounted for individually and in the calculation of POM EF, its contribution here is discounted so as to avoid double-counting.

Trace Metal Compounds EF Basis: AP-42, Table 1.4-4, July 1998.
EF (lb/MMBtu) = EF (lb/1x10^6 scf) X (1x10^6 scf/1020 MMBtu). See footnote a to Table 1.4-4.

Organic Compound EF Basis: AP-42, Table 1.4-3, July 1998.

POM Compounds	EF (lb/10^6 scf)	EF (lb/MMBtu)
2-Methylnaphthalene*	2.4E-05	2.4E-08
3-Methychloranthrene*	1.8E-06	1.8E-09
7,12-Dimethylbenz(a)anthracene*	1.6E-05	1.6E-08
Acenaphthene*	1.8E-06	1.8E-09
Acenaphthylene*	1.8E-06	1.8E-09
Anthracene*	2.4E-06	2.4E-09
Benzo(a)anthracene*	1.8E-06	1.8E-09
Benzo(a)pyrene*	1.2E-06	1.2E-09
Benzo(b)fluoranthene*	1.8E-06	1.8E-09
Benzo(g,h,l)perylene*	1.2E-06	1.2E-09
Benzo(k)fluoranthene*	1.8E-06	1.8E-09
Chrysene*	1.8E-06	1.8E-09
Dibenzo(a,h)anthracene*	1.2E-06	1.2E-09
Fluoranthene*	3.0E-06	2.9E-09
Fluorene*	2.8E-06	2.7E-09
Indeno(1,2,3-cd)pyrene*	1.8E-06	1.8E-09
Naphthalene*,**	6.1E-04	6.0E-07
Phenanthrene*	1.7E-05	1.7E-08
Pyrene*	5.0E-06	4.9E-09
SUBTOTAL	7.0E-04	6.8E-07

* designates a polycyclic aromatic hydrocarbon (PAH). PAHs are potent atmospheric pollutants that consist of fused aromatic rings and do not contain heteroatoms or
** designates a POM compound that is also an individual HAP.

HAP & Non-HAP Potential to Emit

Emission Unit: **EU-9**

Description: System Blowdown Gas

Once per year the source conducts an annual Emergency Shutdown Test where the source is isolated from the natural gas line and the system is purged venting natural gas to the atmosphere.

Control Device: none

Natural Gas Purged: 0.35 $1x10^6$ scf

NON-FUGITIVE EMISSIONS

HAP & Non-HAP Emissions	EF ($lb/1x10^6$ scf)	PTE (tpy)	EF Reference
Hexane (HAP)	3.19E+01	0.01	1
Hydrogen Sulfide (H_2S)	3.21E+01	0.01	2
Lead (Pb)	5.00E-04	8.8E-08	3
Volatile Organic Compounds (VOC)	1.02E+03	0.2	4

NON-FUGITIVE EMISSIONS

Greenhouse Gas Emissions (CO_2 Equivalent)	EF ($lb/1x10^6$ scf)	PTE (tpy)	EF Reference
Methane (CH_4)	1.02E+06	177.8	5

EF Reference	Description
1	EF (lb Hexane/$1x10^6$ scf) = (MW_{gas}) X (wt. % Hexane/100) / ($Density_{gas}$) X $CF_{100scf \to MMscf}$ Values for variables provided by applicant.

Hexane EF for CH_4 ($lb/1x10^6$ scf)	MW_{gas} (lb/lb-mol)	wt. % VOC/100 (unitless)	$Density_{gas}$ (scf/lb mol)	$CF_{scf \to MMscf}$ ($scf/1x10^6$ scf)
3.19E+01	19.25	0.000628	379	1.0E+06

EF Reference	Description
2	Basis: FERC natural gas pipeline tariff sulfur limit of 20 gr/100 standard cubic feet. EF ($lb/1x10^6$ scf) = Pipeline tariff S Limit ($gr/100\ ft^3$) X $CF_{100scf \to MMscf}$ / $CF_{gr \to lb}$ X $CF_{S \to H2S}$ • $CF_{S \to H2S}$ = 1.125 lb H_2S/lb S. The MW S is 16 lb/lb-mol, and the MW H_2S is 18 lb/lb-mol. The ratio of H_2S to S = 18/16; 1.125.

Pipeline Tariff Calculate H_2S EF ($lb/1x10^6$ scf)	Pipeline Tariff Fuel Sulfur Limit ($gr/100\ ft^3$)	$CF_{100scf \to MMscf}$ ($100\ scf/1x10^6$ scf)	$CF_{gr \to lb}$ (gr/lb)	$CF_{S \to H2S}$ (lb H_2S/lb S)
3.21E+01	20	10000	7000	1.125

EF Reference	Description
3	Table 1.4-2 of AP-42, July 1998. Lead is a "pass through" pollutant.
4	EF (lb VOC/$1x10^6$ scf) = (MW_{gas}) X (wt. % VOC/100) / ($Density_{gas}$) X $CF_{100scf \to MMscf}$ Values for variables provided by applicant.

VOC EF for CH_4 ($lb/1x10^6$ scf)	MW_{gas} (lb/lb-mol)	wt. % VOC/100 (unitless)	$Density_{gas}$ (scf/lb mol)	$CF_{scf \to MMscf}$ ($scf/1x10^6$ scf)
1.02E+03	19.25	0.019993	379	1.0E+06

EF Reference	Description
5	EF (lb $CO_2e/1x10^6$ scf) = (MW_{gas}) X (wt. % CH_4/100) / ($Density_{gas}$) X $CF_{100scf \to MMscf}$ X GWP_{CH4} (lb CO_2e/lb CH_4) Estimate that wt. % CH_4 in natural gas is 80%.

CO_2e EF for CH_4 (lb $CO_2e/1x10^6$ scf)	MW_{gas} (lb/lb-mol)	wt. % CH_4/100 (unitless)	$Density_{gas}$ (scf/lb mol)	$CF_{scf \to MMscf}$ ($scf/1x10^6$ scf)	40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CH_4)
1.02E+06	19.25	0.8	379	1.0E+06	25

Non-HAP Potential to Emit

Emission Unit: **EU-10**
Description: Equipment Leaks
Control Device: none

FUGITIVE EMISSIONS

Type of Component	Quantity[a]	Emission Factor[b]	TOC Emissions			VOC Emissions[c]	
		kg/hr/source	kg/hr	lb/hr	tpy	lb/hr	tpy
Valves	196	4.50E-03	8.82E-01	1.944	8.517	0.039	0.170
Flanges	245	3.90E-04	9.56E-02	0.211	0.923	0.004	0.018
Open-Ended Lines	27	2.00E-03	5.40E-02	0.119	0.521	0.002	0.010
Compressor	4	8.80E-03	3.52E-02	0.078	0.340	0.002	0.007
						TOTAL	0.21

[a] Quantity of the components are estimated based on an inventory performed at the Green River compressor station, which is similar to the Pocatello compressor station in equipment and size.
[b] Emission factors are obtained from the document "Protocol for Equipment Leak Estimates," Emission Standards Division, U.S. Environmental Protection Agency, November 1995 Table 2.4.
[c] Average weight fraction of VOC in the stream is estimated as 2.00%. VOC is calculated as Total Organic Carbon (TOC) excluding methane and ethane.

Because VOC for EU-10 approximately equal to VOC for EU-9, and given the similar nature of the emission generating activities, estimate that EU-10 PTE approximately equal to that of EU-9 for hexane, H_2S, lead and methane. A summary of EU-9 potential emissions is transposed here and assumed equal to EU-10 PTE, except that EU-10 emissions are fugitive.

FUGITIVE EMISSIONS

HAP & Non-HAP Emissions	EF ($lb/1x10^6$ scf)	PTE (tpy)
Hexane (HAP)	3.19E+01	0.01
Hydrogen Sulfide (H_2S)	3.21E+01	0.01
Lead (Pb)	5.00E-04	8.8E-08
Volatile Organic Compounds (VOC)	1.02E+03	0.2

FUGITIVE EMISSIONS

Greenhouse Gas Emissions (CO_2 Equivalent)	EF ($lb/1x10^6$ scf)	PTE (tpy)
Methane (CH_4)	1.02E+06	177.8

Non-HAP Potential to Emit

Emission Unit: **EU-11**
Description: Liquid Storage Tanks
Control Device: none

NON-FUGITIVE EMISSIONS

Liquid in Tank	Type of Tank	Capacity (gallons)	VOC PTE (tpy)
Scrubber Oil	Fixed Roof	310	0.1
Scrubber Oil	Fixed Roof	310	0.1
Lube Oil	Horizontal Fixed Roof	11,760	0.1
Used Lube Oil	Vertical Fixed Roof	2,940	0.1
Total			0.4

EPA TANKS 4.0.9d employed to estimate emissions resulting from storage of lube oil and used lube oil. Engineering judgement employed to estimate emissions resulting from storage of scrubber oil.