United States Environmental Protection Agency
Region 10, Office of Air, Waste and Toxics
AWT-150
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101-3140

Permit Number: R10T5110100
Issued: September 30, 2015
Effective: October 31, 2015
Expiration: September 30, 2020
Replaces: R10T5-ID-02-01
AFS Plant I.D. Number: 16-005-00049

Title V Air Quality Operating Permit

Permit Renewal #1

In accordance with the provisions of Title V of the Clean Air Act (42 U.S.C. 7401 *et seq.*), and 40 CFR Part 71 and other applicable rules and regulations,

Williams Corporation, Northwest Pipeline LLC
Pocatello Compressor Station

is authorized to operate air emission units and to conduct other air pollutant emitting activities in accordance with the conditions listed in this permit. This source is authorized to operate in the following location:

Location:	Fort Hall Indian Reservation 2605 Gas Plant Road Pocatello, Idaho Latitude: 42° 48' 55" N Longitude: 112° 42' 13" W
Responsible Official:	Robert Harmon, Director of Operations Northwest Pipeline LLC PO Box 58900 Salt Lake City, UT 84158-0900 Phone: 801-584-6856
Company Contact:	Derek Forsberg Northwest Pipeline LLC Environmental Compliance P.O. Box 58900 Salt Lake City, UT 84158-0900 Phone: 801-584-6748 E-mail: Derek.Forsberg@williams.com

The United States Environmental Protection Agency (EPA) has also developed a statement of basis that describes the bases for conditions contained in this permit.

Donald A. Dossett

Donald A. Dossett, P.E., Manager
Air Permits and Diesel Unit
Office of Air, Waste and Toxics
U.S. EPA, Region 10

Sept. 30, 2015
Date

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1. Source Information and Emission Units

The Pocatello Compressor Station operates remotely from Northwest Pipeline's headquarters located in Salt Lake City, Utah. The compressor station is used to transmit natural gas along the company's natural gas pipeline. All emission units are fired exclusively on natural gas. The emission units are listed in Table 1.

Table 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 Lube Oil Tank, 2,940 gallons (70 BBL); Used Lube Oil Tank 2,940 gallons (70 BBL); (2) Scrubber Oil Tanks 310 gallons per tank (7.4 BBL) - Scrubber tanks store oil that is removed (knockout) from the natural gas prior to compression.	None

* Insignificant Emission Units (IEU).

2. Standard Terms and Conditions

2.1. Terms not otherwise defined in this permit have the meaning assigned to them in the referenced regulations. The language of the cited regulation takes precedence over paraphrasing except the text of terms specified pursuant to any of the following sections is directly enforceable: section 304(f)(4) of the Federal Clean Air Act (CAA), 40 CFR §§ 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii), and 71.6(b), or any other term specifically identified as directly enforceable.

Compliance with the Permit

2.2. The permittee must comply with all conditions of this Part 71 permit. All terms and conditions of this permit are enforceable by the EPA and citizens under the Clean Air Act. Any permit noncompliance constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. [40 CFR § 71.6(a)(6)(i)]

2.3. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. [40 CFR § 71.6(a)(6)(ii)]

Permit Shield

2.4. Compliance with the terms and conditions of this permit shall be deemed compliance with the applicable requirements specifically listed in this permit as of the date of permit issuance. [40 CFR § 71.6(f)(1)]

2.5. Nothing in this permit shall alter or affect the following:

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

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

2.5.3. The applicable requirements of the acid rain program, consistent with section 408(a) of the Clean Air Act; or

2.5.4. The ability of the EPA to obtain information under section 114 of the Clean Air Act.

[40 CFR § 71.6(f)(3)]

Other Credible Evidence

2.6. For the purpose of submitting compliance certifications in accordance with Condition 3.49 of this permit, or establishing whether or not a person has violated or is in violation of any requirement of this permit, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [Section 113(a) and 113(e)(1) of the CAA, 40 CFR §§ 51.212, 52.12 and 52.33]

Permit Actions

2.7. This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR § 71.6(a)(6)(iii)]

2.8. The permit may be reopened by the EPA and the permit revised prior to expiration under any of the circumstances described in 40 CFR § 71.7(f). [40 CFR § 71.7(f)]

Permit Expiration and Renewal

2.9. This permit shall expire on the expiration date on page one of this permit or on an earlier date if the source is issued a Part 70 or Part 71 permit by a permitting authority under an EPA approved or delegated permit program. [40 CFR § 71.6(a)(11)]

2.10. Expiration of this permit terminates the permittee's right to operate unless a timely and complete permit renewal application has been submitted at least six months, but not more than 18 months, prior to the date of expiration of this permit.
[40 CFR §§ 71.5(a)(1)(iii), 71.7(b) and 71.7(c)(1)(ii)]

2.11. If the permittee submits a timely and complete permit application for renewal, consistent with 40 CFR § 71.5(a)(2), but the EPA has failed to issue or deny the renewal permit, then all the terms and conditions of the permit, including any permit shield granted pursuant to 40 CFR § 71.6(f) shall remain in effect until the renewal permit has been issued or denied. This permit shield shall cease to apply if, subsequent to the completeness determination, the permittee fails to submit by the deadline specified in writing by the EPA any additional information identified as being needed to process the application. [40 CFR §§ 71.7(c)(3) and 71.7(b)]

Off-Permit Changes

2.12. The permittee is allowed to make certain changes without a permit revision, provided that the following requirements are met:

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

2.12.2. Each change meets all applicable requirements and does not violate any existing permit term or condition;

2.12.3. The changes are not changes subject to any requirement of 40 CFR Parts 72 through 78 or modifications under any provision of Title I of the Clean Air Act;

2.12.4. The permittee provides contemporaneous written notice to the EPA of each change, except for changes that qualify as insignificant activities under 40 CFR § 71.5(c)(11), that describes each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change;

2.12.5. The changes are not covered by a permit shield provided under 40 CFR § 71.6(f) and Conditions 2.4 and 2.5 of this permit; and

2.12.6. The permittee keeps a record describing all changes that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes.

[40 CFR § 71.6(a)(12)]

Emissions Trading and Operational Flexibility

2.13. The permittee is allowed to make a limited class of changes under section 502(b)(10) of the Clean Air Act within this permitted facility that contravene the specific terms of this permit without applying for a permit revision, provided:

2.13.1. The changes do not exceed the emissions allowable under this permit (whether expressed therein as a rate of emissions or in terms of total emissions);

2.13.2. The changes are not modifications under any provision of Title I of the Clean Air Act;

2.13.3. The changes do not violate applicable requirements;

2.13.4. The changes do not contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements;

2.13.5. The permittee sends a notice to the EPA, at least seven days in advance of any change made under this provision, that describes the change, when it will occur and any change in emissions and identifies any permit terms or conditions made inapplicable as a result of the change and the permittee attaches each notice to its copy of this permit; and

2.13.6. The changes are not covered by a permit shield provided under 40 CFR § 71.6(f) and Conditions 2.4 and 2.5 of this permit.

[40 CFR § 71.6(a)(13)(i)]

2.14. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit. [40 CFR § 71.6(a)(8)]

Severability

2.15. The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any portion is held invalid, the remaining permit conditions shall remain valid and in force. [40 CFR § 71.6(a)(5)]

Property Rights

2.16. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR § 71.6(a)(6)(iv)]

3. General Requirements

General Compliance Schedule

3.1. For applicable requirements with which the source is in compliance, the permittee will continue to comply with such requirements. [40 CFR §§ 71.6(c)(3) and 71.5(c)(8)(iii)(A)]

3.2. For applicable requirements that will become effective during the permit term, the permittee shall meet such requirements on a timely basis. [40 CFR §§ 71.6(c)(3) and 71.5(c)(8)(iii)(B)]

Inspection and Entry

3.3. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the EPA or an authorized representative to perform the following:

3.3.1. Enter upon the permittee's premises where a Part 71 source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

3.3.2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

3.3.3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

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

[40 CFR § 71.6(c)(2)]

Open Burning Restrictions

3.4. Except as exempted in 40 CFR § 49.131(c), the permittee shall not openly burn, or allow the open burning of, the following materials:

3.4.1. Garbage;

3.4.2. Dead animals or parts of dead animals;

3.4.3. Junked motor vehicles or any materials resulting from a salvage operation;

3.4.4. Tires or rubber materials or products;

3.4.5. Plastics, plastic products, or styrofoam;

3.4.6. Asphalt or composition roofing, or any other asphaltic material or product;

3.4.7. Tar, tarpaper, petroleum products, or paints;

3.4.8. Paper, paper products, or cardboard other than what is necessary to start a fire or that is generated at single-family residences or residential buildings with four or fewer dwelling units and is burned at the residential site;

3.4.9. Lumber or timbers treated with preservatives;

3.4.10. Construction debris or demolition waste;

3.4.11. Pesticides, herbicides, fertilizers, or other chemicals;

3.4.12. Insulated wire;

3.4.13. Batteries;

3.4.14. Light bulbs;

3.4.15. Materials containing mercury (e.g., thermometers);

3.4.16. Asbestos or asbestos-containing materials;

3.4.17. Pathogenic wastes;

3.4.18. Hazardous wastes; or

3.4.19. Any material other than natural vegetation that normally emits dense smoke or noxious fumes when burned.

[40 CFR §§ 49.131(c) and (d)(1)]

3.5. Open burning shall be conducted as follows:

3.5.1. All materials to be openly burned shall be kept as dry as possible through the use of a cover or dry storage;

3.5.2. Before igniting a burn, noncombustibles shall be separated from the materials to be openly burned to the greatest extent practicable;

3.5.3. Natural or artificially induced draft shall be present, including the use of blowers or air curtain incinerators where practicable;

3.5.4. To the greatest extent practicable, materials to be openly burned shall be separated from the grass or peat layer; and

3.5.5. A fire shall not be allowed to smolder.

[40 CFR § 49.131(e)(1)]

3.6. Except for exempted fires set for cultural or traditional purposes, a person shall not initiate any open burning when:

3.6.1. The Regional Administrator has declared a burn ban; or

3.6.2. An air stagnation advisory has been issued or an air pollution alert, warning or emergency has been declared by the Regional Administrator.

[40 CFR §§ 49.131(d)(2), (d)(3) and (e)(2), and 49.137(c)(4)(i)]

3.7. Except for exempted fires set for cultural or traditional purposes, any person conducting open burning when such an advisory is issued or declaration is made shall either immediately extinguish the fire, or immediately withhold additional material such that the fire burns down.
[40 CFR §§ 49.131(e)(3) and 49.137(c)(4)(ii)]

3.8. Nothing in this section exempts or excuses any person from complying with applicable laws and ordinances of local fire departments and other governmental jurisdictions.
[40 CFR § 49.131(d)(4)]

Visible Emissions Limits

3.9. Except as provided for in Conditions 3.10 and 3.11, the visible emissions from any air pollution source that emits, or could emit, particulate matter or other visible air pollutants shall not exceed 20% opacity, averaged over any consecutive six-minute period. Compliance with this emission limit is determined as follows:

3.9.1. Using EPA Reference Method 9 found in Appendix A of 40 CFR Part 60; or

3.9.2. Alternatively, using a continuous opacity monitoring system that complies with Performance Specification 1 found in Appendix B of 40 CFR Part 60.

[40 CFR §§ 49.124(d)(1) and (e)]

3.10. The requirements of Condition 3.9 do not apply to open burning, agricultural activities, forestry and silvicultural activities, non-commercial smoke houses, sweat houses or lodges, smudge pots, furnaces and boilers used exclusively to heat residential buildings with four or fewer dwelling units, or emissions from fuel combustion in mobile sources. [40 CFR § 49.124(c)]

3.11. Exception to the visible emission limit in Condition 3.9 includes:

3.11.1. The visible emissions from an air pollution source may exceed the 20% opacity limit if the owner or operator of the air pollution source demonstrates to the Regional Administrator's satisfaction that the presence of uncombined water, such as steam, is the only reason for the failure of an air pollution source to meet the 20% opacity limit.

[40 CFR § 49.124(d)(2)]

Fugitive Particulate Matter Requirements and Recordkeeping

3.12. Except as provided for in Condition 3.17, the permittee shall take all reasonable precautions to prevent fugitive particulate matter emissions and shall maintain and operate all pollutant-emitting activities to minimize fugitive particulate matter emissions. Reasonable precautions include, but are not limited to the following:

3.12.1. Use, where possible, of water or chemicals for control of dust in the demolition of buildings or structures, construction operations, grading of roads, or clearing of land;

3.12.2. Application of asphalt, oil (but not used oil), water, or other suitable chemicals on unpaved roads, materials stockpiles, and other surfaces that can create airborne dust;

3.12.3. Full or partial enclosure of materials stockpiles in cases where application of oil, water, or chemicals is not sufficient or appropriate to prevent particulate matter from becoming airborne;

3.12.4. Implementation of good housekeeping practices to avoid or minimize the accumulation of dusty materials that have the potential to become airborne, and the prompt cleanup of spilled or accumulated materials;

3.12.5. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials;

3.12.6. Adequate containment during sandblasting or other similar operations;

3.12.7. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne; and

3.12.8. The prompt removal from paved streets of earth or other material that does or may become airborne.

[40 CFR §§ 49.126(d)(1) and (2)]

3.13. Once each calendar year, during typical operating conditions and meteorological conditions conducive to producing fugitive dust, the permittee shall survey the facility to determine the sources of fugitive particulate matter emissions. For new sources or new operations, a survey shall be conducted within 30 days after commencing operation.

3.13.1. The permittee shall record the results of the survey, including the date and time of the survey and identification of any sources of fugitive particulate matter emissions found; and

3.13.2. If sources of fugitive particulate matter emissions are present, the permittee shall determine the reasonable precautions that will be taken to prevent fugitive particulate matter emissions.

[40 CFR §§ 49.126(e)(1)(i) and (ii)]

3.14. The permittee shall prepare, and update as necessary following each survey, a written plan that specifies the reasonable precautions that will be taken and the procedures to be followed to prevent fugitive particulate matter emissions, including appropriate monitoring and recordkeeping.

3.14.1. For construction or demolition activities, a written plan shall be prepared prior to commencing construction or demolition.

[40 CFR § 49.126(e)(1)(iii)]

3.15. The permittee shall implement the written plan, and maintain and operate all sources to minimize fugitive particulate matter emissions. [40 CFR § 49.126(e)(1)(iv)]

3.16. Efforts to comply with this section cannot be used as a reason for not complying with other applicable laws and ordinances. [40 CFR § 49.126(e)(3)]

3.17. The requirements of Conditions 3.12 through 3.16 do not apply to open burning, agricultural activities, forestry and silvicultural activities, sweat houses or lodges, non-commercial smoke houses, or activities associated with single-family residences or residential buildings with four or fewer dwelling units. [40 CFR § 49.126(c)]

Other Work Practice Requirements and Recordkeeping

3.18. The permittee shall comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR Part 68 no later than the latest of the following dates:

3.18.1. Three years after the date on which a regulated substance, present above the threshold quantity in a process, is first listed under 40 CFR § 68.130; or

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

[40 CFR § 68.10]

3.19. Except as provided for motor vehicle air conditioners (MVACs) in 40 CFR Part 82, Subpart B, the permittee shall comply with the stratospheric ozone and climate protection standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F.

3.19.1. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR § 82.156.

3.19.2. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR § 82.158.

3.19.3. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR § 82.161.

3.19.4. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with recordkeeping requirements pursuant to 40 CFR § 82.166. ("MVAC-like appliance" is defined at 40 CFR § 82.152.)

3.19.5. Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to 40 CFR § 82.156.

3.19.6. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR § 82.166.

[40 CFR Part 82, Subpart F]

3.20. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant (or regulated substitute substance) in the MVAC, the permittee must comply with all the applicable requirements for stratospheric ozone and climate protection as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

[40 CFR Part 82, Subpart B]

3.21. The permittee shall comply with 40 CFR Part 61, Subpart M for asbestos removal and disposal when conducting any renovation or demolition at the facility. [40 CFR Part 61, Subpart M]

General Testing and Associated Recordkeeping and Reporting

3.22. In addition to the specific testing requirements contained in the facility and emission unit-specific sections of this permit, the permittee shall comply with the generally applicable testing requirements in Conditions 3.23 through 3.30 whenever conducting a performance test required by this permit unless specifically stated otherwise in this permit.

[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.23. Test Notification. The permittee shall provide the EPA at least 30 days prior notice of any performance test, except as otherwise specified in this permit, to afford the EPA the opportunity to have an observer present. If after 30-day notice for an initially scheduled performance test, there is a delay in conducting the scheduled performance test, the permittee shall notify the EPA as soon as possible of any delay in the original test date, either by providing at least seven days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the EPA by mutual agreement. [40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.24. Test Plan. The permittee shall submit to the EPA a source test plan 30 days prior to any required testing. The source test plan shall include and address the following elements:

3.24.1. Purpose and scope of testing;

3.24.2. Source description, including a description of the operating scenarios and mode of operation during testing and including fuel sampling and analysis procedures;

3.24.3. Schedule/dates of testing;

3.24.4. Process data to be collected during the test and reported with the results, including source-specific data identified in the facility or emission unit-specific sections of this permit;

3.24.5. Sampling and analysis procedures, specifically requesting approval for any proposed alternatives to the reference test methods, and addressing minimum test length (e.g., one hour, eight hours, 24 hours, etc.) and minimum sample volume;

3.24.6. Sampling location description and compliance with the reference test methods;

3.24.7. Analysis procedures and laboratory identification;

3.24.8. Quality assurance plan;

3.24.9. Calibration procedures and frequency;

3.24.10. Sample recovery and field documentation;

3.24.11. Chain of custody procedures;

3.24.12. Quality assurance/quality control project flow chart;

3.24.13. Data processing and reporting;

3.24.14. Description of data handling and quality control procedures; and

3.24.15. Report content and timing.

[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.25. Facilities for performing and observing the emission testing shall be provided that meet the requirements of 40 CFR 60.8(e) and Reference Method 1 (40 CFR Part 60, Appendix A).
[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.26. Unless the EPA determines in writing that other operating conditions are representative of normal operations or unless specified in the facility or emission unit-specific sections of this permit, the source shall be operated at a capacity of at least 90% but no more than 100% of maximum during all tests. [40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.27. Only regular operating staff may adjust the processes or emission control devices during or within two hours prior to the start of a source test. Any operating adjustments made during a source test, that are a result of consultation during the tests with source testing personnel, equipment vendors, or consultants, may render the source test invalid. [40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.28. Each source test shall follow the reference test methods specified by this permit and consist of at least three valid test runs.

3.28.1. If the reference test method yields measured pollutant concentration values at an oxygen concentration other than specified in the emission standard, the permittee shall correct the measured pollutant concentration to the oxygen concentration specified in the emission standard by using the following equation:

$$PC_X = PC_M \times \frac{(20.9 - X)}{(20.9 - Y)}$$

Where: PC_X = Pollutant concentration at X percent;
PC_M = Pollutant concentration as measured;
X = Oxygen concentration specified in the standard; and
Y = Measured average volumetric oxygen concentration.

[40 CFR § 71.6(a)(3)(i)(B)]

3.28.2. Source test emission data shall be reported as the arithmetic average of all valid test runs and in the terms of any applicable emission limit, unless otherwise specified in the facility or emission unit-specific sections of this permit.
[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.29. Test Records. For the duration of each test run (unless otherwise specified), the permittee shall record the following information:

3.29.1. All data which is required to be monitored during the test in the facility or emission unit-specific sections of this permit; and

3.29.2. All continuous monitoring system data which is required to be routinely monitored in the facility or emission unit-specific sections of this permit for the emission unit being tested.

[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.30. Test Reports. Unless the EPA approves in writing a different due date, emission test reports shall be submitted to the EPA within 60 days of completing any emission test required by this permit along with data required to be recorded in Condition 3.29 above.
[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

General Recordkeeping

3.31. Monitoring Records. The permittee shall keep records of required monitoring information that include the following:

3.31.1. The date, place, and time of sampling or measurements;

3.31.2. The date(s) analyses were performed;

3.31.3. The company or entity that performed the analyses;

3.31.4. The analytical techniques or methods used;

3.31.5. The results of such analyses; and,

3.31.6. The operating conditions as existing at the time of sampling or measurement.

[40 CFR § 71.6(a)(3)(ii)(A)]

3.32. Off-Permit Change Records. The permittee shall keep a record describing all off-permit changes allowed to be made under Condition 2.12 that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes. [40 CFR § 71.6(a)(12)]

3.33. Open Burning Records. For any open burning allowed under Conditions 3.4 through 3.8, the permittee shall document the following:

3.33.1. The date that burning was initiated;

3.33.2. The duration of the burn;

3.33.3. The measures taken to comply with each provision of Condition 3.5; and

3.33.4. The measures taken to ensure that materials prohibited in Condition 3.4 were not burned.

[40 CFR § 71.6(a)(3)(i)(B)]

3.34. Fee Records. The permittee shall retain in accordance with the provisions of Condition 3.35 of this permit, all work sheets and other materials used to determine fee payments. Records shall be retained for five years following the year in which the emissions data is submitted.

[40 CFR § 71.9(i)]

3.35. Records Maintenance and Retention. The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this permit recorded in a permanent form suitable for inspection. The permittee shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, recording, report, or application. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

[40 CFR §§ 71.6(a)(3), 71.6(c)(1), 49.126(e)(1)(v) and 49.130(f)(2)]

General Reporting

3.36. Additional Information. The permittee shall furnish to the EPA, within a reasonable time, any information that the EPA may request in writing to determine whether cause exists for modifying, revoking, and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the EPA copies of records that are required to be kept pursuant to the terms of the permit, including information claimed to be confidential. Information claimed to be confidential must be accompanied by a claim of confidentiality according to the provisions of 40 CFR Part 2, Subpart B. [40 CFR §§ 71.6(a)(6)(v) and 71.5(a)(3)]

3.37. Corrections. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information. [40 CFR § 71.5(b)]

3.38. Off-Permit Change Report. The permittee shall provide contemporaneous written notice to the EPA of each off-permit change allowed to be made under Condition 2.12, except for changes that qualify as insignificant activities under 40 CFR § 71.5(c)(11). The written notice shall describe each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change; [40 CFR § 71.6(a)(12)]

3.39. Section 502(b)(10) Change Report. The permittee is required to send a notice to the EPA at least 7 days in advance of any section 502(b)(10) change allowed to be made under Condition 2.13. The notice must describe the change, when it will occur and any change in emissions, and identify any permit terms or conditions made inapplicable as a result of the change. The permittee shall attach each notice to its copy of this permit. [40 CFR § 71.6(a)(13)(i)(A)]

3.40. Address. Unless otherwise specified in this permit, any documents required to be submitted under this permit, including reports, test data, monitoring data, notifications, compliance certifications, fee calculation worksheets, and applications for renewals and permit modifications shall be submitted to the EPA address below. A copy of each document submitted to the EPA that does not contain confidential business information shall be sent to the Tribal address below:

Original documents go to the EPA at:	Copies go to the Tribe at:
Part 71 Air Quality Permits U.S. EPA - Region 10, AWT-150 1200 Sixth Avenue, Suite 900 Seattle, WA 98101-3140	Air Quality Program Manager Shoshone-Bannock Tribes P.O. Box 306 Fort Hall, Idaho 83203

[40 CFR §§ 71.5(d), 71.6(c)(1) and 71.9(h)(2)]

Part 71 Emission and Fee Reporting

3.41. Part 71 Annual Emission Report. No later than the date specified in Condition 4.1 of each year, the permittee shall submit to the EPA an annual report of actual emissions for the preceding calendar year. [40 CFR § 71.9(h)(1)]

3.41.1. "Actual emissions" means the actual rate of emissions in tons per year of any "regulated pollutant (for fee calculation)," as defined in 40 CFR § 71.2, emitted from a Part 71 source over the preceding calendar year. Actual emissions shall be calculated using each emissions unit's actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year. [40 CFR § 71.9(c)(6)]

3.41.2. Actual emissions shall be computed using methods required by the permit for determining compliance. [40 CFR § 71.9(h)(3)]

3.41.3. Actual emissions shall include fugitive emissions. [40 CFR § 71.9(c)(1)]

3.42. Part 71 Fee Calculation Worksheet. Based on the annual emission report required in Condition 3.41 and no later than the date specified in Condition 4.1 of each year, the permittee shall submit to the EPA a fee calculation worksheet (blank forms provided by the EPA) and a photocopy of each fee payment check (or other confirmation of actual fee paid). [40 CFR §§ 71.9(c)(1), 71.9(e)(1) and 71.9(h)(1)]

3.42.1. The annual emissions fee shall be calculated by multiplying the total tons of actual emissions of each "regulated pollutant (for fee calculation)," emitted from the source by the presumptive emission fee (in dollars/ton) in effect at the time of calculation. The presumptive emission fee is revised each calendar year and is available from the EPA prior to the start of each calendar year. [40 CFR § 71.9(c)(1)]

3.42.2. The permittee shall exclude the following emissions from the calculation of fees:

3.42.2.1 The amount of actual emissions of each regulated pollutant (for fee calculation) that the source emits in excess of 4,000 tons per year;

3.42.2.2 Actual emissions of any regulated pollutant (for fee calculation) already included in the fee calculation; and

3.42.2.3 The insignificant quantities of actual emissions not required to be listed or calculated in a permit application pursuant to 40 CFR § 71.5(c)(11).

[40 CFR § 71.9(c)(5)]

3.43. Part 71 Annual Fee Payment. No later than the date specified in Condition 4.1 of each year, the permittee shall submit to the EPA full payment of the annual permit fee based on the fee calculation worksheet required in Condition 3.42. [40 CFR §§ 71.9(a), 71.9(c)(1) and 71.9(h)(1)]

3.43.1. The fee payment and a completed fee filing form shall be sent to:

U.S.EPA
FOIA and Miscellaneous Payments
Cincinnati Finance Center
P. O. Box 979078
St Louis, MO 63197-9000

[40 CFR § 71.9(k)(2)]

3.43.2. The fee payment shall be in United States currency and shall be paid by money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the order of the U.S. Environmental Protection Agency. [40 CFR § 71.9(k)(1)]

3.43.3. The permittee, when notified by the EPA of additional amounts due, shall remit full payment within 30 days of receipt of an invoice from the EPA. [40 CFR § 71.9(j)(2)]

3.43.4. If the permittee thinks an EPA assessed fee is in error and wishes to challenge such fee, the permittee shall provide a written explanation of the alleged error to the EPA along with full payment of the EPA assessed fee. [40 CFR § 71.9(j)(3)]

3.43.5. Failure of the permittee to pay fees in a timely manner shall subject the permittee to assessment of penalties and interest in accordance with 40 CFR § 71.9(l). [40 CFR § 71.9(l)]

3.44. The annual emission report and fee calculation worksheet (and photocopy of each fee payment check), required in Conditions 3.41 and 3.42, shall be submitted to the EPA at the address listed in Condition 3.40 of this permit.[1] [40 CFR § 71.9(k)(1)]

3.45. The annual emission report and fee calculation worksheet (and photocopy of each fee payment check), required in Conditions 3.41 and 3.42, shall be certified by a responsible official in accordance with Condition 3.50 of this permit. [40 CFR § 71.9(h)(2)]

Annual Registration

3.46. The permittee shall submit an annual registration report that consists of estimates of the total actual emissions from the air pollution source for the following air pollutants: PM, PM_{10}, $PM_{2.5}$, SO_X, NO_X, CO, VOC, lead and lead compounds, ammonia, fluorides (gaseous and particulate), sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds, including all calculations for the estimates. Emissions shall be calculated using the actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year. [40 CFR §§ 49.138(e)(3)(xii), (e)(4) and (f)]

3.46.1. The emission estimates required by Condition 3.46 shall be based upon actual test data or, in the absence of such data, upon procedures acceptable to the Regional Administrator. Any emission estimates submitted to the Regional Administrator shall be verifiable using currently accepted engineering criteria. The following procedures are generally acceptable for estimating emissions from air pollution sources:

3.46.1.1 Source-specific emission tests;

3.46.1.2 Mass balance calculations;

3.46.1.3 Published, verifiable emission factors that are applicable to the source;

3.46.1.4 Other engineering calculations; or

[1] The permittee should note that an annual emissions report, required at the same time as the fee calculation worksheet by 40 CFR § 71.9(h), has been incorporated into the fee calculation worksheet.

3.46.1.5 Other procedures to estimate emissions specifically approved by the Regional Administrator.

[40 CFR §§ 49.138(e)(4) and (f)]

3.46.2. The annual registration report shall be submitted with the annual emission report and fee calculation worksheet required by Conditions 3.41 and 3.42 of this permit. The permittee may submit a single combined report provided that the combined report clearly identifies which emissions are the basis for the annual registration report, the Part 71 annual emission report, and the Part 71 fee calculation worksheet. All registration information and reports shall be submitted on forms provided by the Regional Administrator.
[40 CFR §§ 49.138(d) and (f)]

Periodic and Deviation Reporting

3.47. Semi-Annual Monitoring Report. The permittee shall submit to the EPA reports of any required monitoring for each six month reporting period from July 1 to December 31 and from January 1 to June 30. All reports shall be submitted to the EPA and shall be postmarked by the 60th day following the end of the reporting period. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with Condition 3.50. [40 CFR § 71.6(a)(3)(iii)(A)]

3.48. Deviation Report. The permittee shall promptly report to the EPA, by telephone or facsimile, deviations from permit conditions, including those attributable to upset conditions as defined in this permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be made using the following numbers:

Telephone: (206) 553-1331
Attn: Part 71 Deviation Report

[40 CFR § 71.6(a)(3)(iii)(B)]

3.48.1. For the purposes of Conditions 3.47 and 3.48, deviation means any situation in which an emissions unit fails to meet a permit term or condition. A deviation is not always a violation. A deviation can be determined by observation or through review of data obtained from any testing, monitoring, or record keeping required by this permit. For a situation lasting more than 24 hours, each 24-hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

3.48.1.1 A situation where emissions exceed an emission limitation or standard;

3.48.1.2 A situation where process or emissions control device parameter values indicate that an emission limitation or standard has not been met;

3.48.1.3 A situation in which observations or data collected demonstrate noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit (including indicators of compliance revealed through parameter monitoring);

3.48.1.4 A situation in which any testing, monitoring, recordkeeping or reporting required by this permit is not performed or not performed as required;

3.48.1.5 A situation in which an exceedance or an excursion, as defined in 40 CFR Part 64, occurs; and

3.48.1.6 Failure to comply with a permit term that requires submittal of a report.

[40 CFR § 71.6(a)(3)(iii)(C)]

3.48.2. For the purpose of Condition 3.48 of the permit, prompt is defined as any definition of prompt or a specific time frame for reporting deviations provided in an underlying applicable requirement as identified in this permit. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

3.48.2.1 For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report must be made within 24 hours of the occurrence;

3.48.2.2 For emissions of any regulated pollutant excluding those listed in Condition 3.48.2.1 above, that continue for more than two hours in excess of permit requirements, the report must be made within 48 hours of the occurrence; or

3.48.2.3 For all other deviations from permit requirements, the report shall be submitted with the semi-annual monitoring report required in Condition 3.47.

[40 CFR § 71.6(a)(3)(iii)(B)]

3.48.3. Within ten working days of the occurrence of a deviation as provided in Condition 3.48.2.1 or 3.48.2.2 above, the permittee shall also submit a written notice, which shall include a narrative description of the deviation and updated information as listed in Condition 3.48, to the EPA, certified consistent with Condition 3.50 of this permit.
[40 CFR §§ 71.6(a)(3)(i)(B) and (iii)(B)]

Annual Compliance Certification

3.49. The permittee shall submit to the EPA a certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices, postmarked by February 28 of each year and covering the permit or permits in effect during the previous calendar year. The compliance certification shall be certified as to truth, accuracy, and completeness by a responsible official consistent with Condition 3.50 of this permit. [40 CFR § 71.6(c)(5)]

3.49.1. The annual compliance certification shall include the following:

3.49.1.1 The identification of each permit term or condition that is the basis of the certification;

3.49.1.2 The identification of the method(s) or other means used by the permittee for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required in this permit. If necessary, the permittee also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information; and

3.49.1.3 The status of compliance with each term and condition of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred.

[40 CFR § 71.6(c)(5)(iii)]

Document Certification

3.50. Any document required to be submitted under this permit shall be certified by a responsible official as to truth, accuracy, and completeness. Such certifications shall state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. [40 CFR §§ 71.5(d), 71.6(c)(1) and 71.9(h)(2)]

Permit Renewal

3.51. The permittee shall submit a timely and complete application for permit renewal at least six months, but not more than 18 months, prior to the date of expiration of this permit. [40 CFR §§ 71.5(a)(1)(iii), 71.7(b) and 71.7(c)(1)(ii)]

3.52. The application for renewal shall include the current permit number, a description of permit revisions and off-permit changes that occurred during the permit term and were not incorporated into the permit during the permit term, any applicable requirements that were promulgated and not incorporated into the permit during the permit term, and other information required by the application form. [40 CFR §§ 71.5(a)(2) and 71.5(c)(5)]

4. Facility-Specific Requirements

Fees and Emission Reports Due Date

4.1. Unless otherwise specified, fees and emission reports required by this permit are due annually on April 1. [40 CFR §§ 71.9(a) and 71.9(h)]

Fuel Restriction

4.2. The permittee is prohibited from combusting any fuel other than natural gas in any emission unit. [Section 304(f)(4) of the Federal Clean Air Act and 40 CFR § 71.6(b)]

Fuel Sulfur Limits

4.3. The permittee shall not sell, distribute, use, or make available for use any gaseous fuel that contains more than 1.1 grams of sulfur per dry standard cubic meter. [40 CFR § 49.130(d)(8)]

4.3.1. Compliance with the sulfur limit is determined using ASTM methods D1072-90 (Reapproved 1999), D3246-96, D4084-94 (Reapproved 1999), D5504-01, D4468-85 (Reapproved 2000), D2622-03, and D6228-98 (Reapproved 2003) (incorporated by reference, see §49.123(e)). [40 CFR § 49.130(e)(4)]

Fuel Sulfur Monitoring and Recordkeeping

4.4. The permittee shall keep records consisting of a current, valid purchase contract, tariff sheet or transportation contract for the fuel showing that the gaseous fuel meets the definition of natural gas in 40 CFR § 72.2. [40 CFR §§ 49.130(f)(1)(ii), 71.6(a)(3)(i)(B) and 71.6(c)]

Combustion Source Stack Emission Limits

4.5. Sulfur dioxide emissions from each combustion source stack shall not exceed an average of 500 parts per million by volume, on a dry basis and corrected to seven percent oxygen, during any three-hour period.

4.5.1. Compliance with the SO_2 limit is determined using EPA Reference Methods 6, 6A, 6B, and 6C as specified in the applicability section of each method (see 40 CFR Part 60, appendix A) or, alternatively, a continuous emission monitoring system (CEMS) that complies with Performance Specification 2 found in Appendix B of 40 CFR Part 60.

[40 CFR §§ 49.129(d)(1) and (e)]

4.6. Particulate matter emissions from each combustion source stack shall not exceed an average of 0.23 grams per dry standard cubic meter (0.1 grains per dry standard cubic foot), corrected to seven percent oxygen, during any three-hour period.

4.6.1. Compliance with the PM limit is determined using EPA Reference Method 5 (see 40 CFR Part 60, Appendix A).

[40 CFR §§ 49.125(d)(1) and (e)]

Visible and Fugitive Emission Monitoring and Recordkeeping

4.7. Once each calendar quarter, the permittee shall visually survey each emission unit and any other pollutant emitting activity for the presence of visible emissions or fugitive emissions of particulate matter.

4.7.1. The observer conducting the visual survey must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting and wind, and the presence of uncombined water on the visibility of emissions (see 40 CFR Part 60, Appendix A, Method 22).

4.7.2. For the surveys, the observer shall select a position that enables a clear view of the emission point to be surveyed, that is at least 15 feet, but not more than 0.25 miles, from the emission point, and where the sunlight is not shining directly in the observer's eyes.

4.7.3. The observer shall continuously watch for visible emissions from each potential emission point for at least 15 seconds.

4.7.4. Any observed visible emissions or fugitive emissions of particulate matter (other than uncombined water) shall be recorded as a positive reading associated with the emission unit or pollutant emitting activity.

4.7.5. Surveys shall be conducted while the emission unit or pollutant emitting activity is operating, and during daylight hours.

[40 CFR § 71.6(a)(3)(i)(B)]

4.8. If the survey conducted pursuant to Condition 4.7 identifies any visible emissions or fugitive emissions of particulate matter, the permittee shall:

4.8.1. Immediately upon conclusion of the visual survey in Condition 4.7, investigate the source and reason for the presence of visible emissions or fugitive emissions; and

4.8.2. As soon as practicable, take appropriate corrective action.

[40 CFR § 71.6(a)(3)(i)(B)]

4.9. If the corrective actions undertaken pursuant to Condition 4.8.2 do not eliminate the visible or fugitive emissions, the permittee shall within 24 hours of the visual survey in Condition 4.7 determine the opacity of the emissions in question, for a 30-minute duration, using the procedures specified in Condition 3.9.1. [40 CFR § 71.6(a)(3)(i)(B)]

4.10. If any 6-minute average opacity determined pursuant to Condition 4.9 or 4.11 is greater than 20%, the permittee shall determine the opacity of the emissions in question daily, for a 30-minute duration each day, using the procedures specified in Condition 3.9.1 until no 6-minute average opacity is greater than 20% for two consecutive days. [40 CFR § 71.6(a)(3)(i)(B)]

4.11. If the opacity determination required in Condition 4.9, or if two consecutive daily opacity determinations required by Condition 4.10, indicate no 6-minute average opacity greater than 20%, the permittee shall determine opacity of the emissions in question weekly, for a 30-minute duration each week, for three additional weeks using the procedures specified in Condition 3.9.1.

[40 CFR § 71.6(a)(3)(i)(B)]

4.12. The permittee shall maintain records of the following:

4.12.1. Details of each visual survey, including date, time, observer and results for each emission unit and any other pollutant emitting activity;

4.12.2. Date, time and type of any investigation conducted pursuant to Condition 4.8.1;

4.12.3. Findings of the investigation, including the reasons for the presence of visible emissions or fugitive emissions of particulate matter;

4.12.4. Date, time and type of corrective actions taken pursuant to Condition 4.8.2;

4.12.5. Field, observation and data reduction records for any EPA Reference Method 9 determination conducted on the source of visible or fugitive emissions pursuant to Conditions 4.9 through 4.11.

[40 CFR § 71.6(a)(3)(i)(B)]

4.13. Any 6-minute average opacity determined to be in excess of 20% is a deviation and subject to the provisions of Conditions 3.47 and 3.48. [40 CFR § 71.6(a)(3)(i)(B)]

Monitoring for PSD Modifications to the Facility

4.14. Where there is a reasonable possibility (as defined in 40 CFR § 52.21(r)(6)(vi)) that a project (other than projects at a source with a plantwide applicability limitation) that is not a part of a major modification may result in a significant emissions increase of any regulated NSR pollutant and the permittee elects to use the method specified in 40 CFR § 52.21(b)(41)(ii)(a) through (c) for calculating projected actual emissions, the permittee shall perform the following:

4.14.1. Before beginning actual construction of the project, document and maintain a record of the following information.

4.14.1.1 A description of the project.

4.14.1.2 Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project.

4.14.1.3 A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under 40 CFR § 52.21(b)(41)(ii)(c) and an explanation for why such amount was excluded, and any netting calculations, if applicable.

4.14.2. Monitor the emission of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in Condition 4.14.1.2; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five years following resumption of regular operations after the change, or for a period of ten years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

[40 CFR § 52.21(r)(6)]

Reporting for PSD Modifications to the Facility

4.15. If monitoring and recordkeeping is required in Condition 4.14.2, the permittee shall report to the EPA when the annual emissions, in tons per year, from the project identified in Condition 4.14.1.1 exceed the baseline actual emissions as documented and maintained pursuant to Condition 4.14.1.3

by a significant amount (as defined in 40 CFR § 52.21(b)(23)) for that regulated NSR pollutant, and when such emissions differ from the preconstruction projection as documented and maintained pursuant to Condition 4.14.1.3. Such report shall be submitted to the EPA within 60 days after the end of such year. The report shall contain the following.

4.15.1. The name, address and telephone number of the major stationary source.

4.15.2. The annual emissions as calculated pursuant to Condition 4.14.2.

4.15.3. Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

[40 CFR § 52.21(r)(6)]

NESHAP Work Practice Requirements

4.16. NESHAP Circumvention. The permittee shall not build, erect, install, or use any article, machine, equipment, or process to conceal an emission that would otherwise constitute noncompliance with a relevant NESHAP standard. Such concealment includes, but is not limited to, the use of diluents to achieve compliance with a relevant standard based on the concentration of a pollutant in the effluent discharged to the atmosphere and the use of gaseous diluents to achieve compliance with a relevant standard for visible emissions. [40 CFR § 63.4(b)]

NESHAP Recordkeeping Requirements

4.17. NESHAP Records. The permittee shall maintain files of all information (including all reports and notifications) required by a NESHAP Standard recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent 2 years of data for Units # 6 and 7 shall be retained on site. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche. [40 CFR § 63.10(b)(1)]

4.18. NESHAP Records. The permittee shall maintain relevant records for such source of all documentation supporting initial notifications and notifications of compliance status under §63.9 (see Condition 4.19). [40 CFR § 63.10(b)(2)(xiv)]

NESHAP Notification and Reporting Requirements

4.19. Notification of Compliance Status. The permittee shall submit a notification of compliance status, signed by the responsible official who shall certify its accuracy, attesting to whether the source has complied, before the close of business on the 60th day following the completion of the relevant compliance demonstration activity specified in Subpart DDDDD for Units #6 and 7. Notifications may be combined as long as the due date requirement for each notification is met. The notification shall include:

[40 CFR 63.9(h)(2)(i) and (ii) and 63.9(h)(3)]

4.19.1. The methods that were used to determine compliance; [40 CFR § 63.9(h)(2)(i)(A)]

4.19.2. The results of any methods that were conducted; [40 CFR § 63.9(h)(2)(i)(B)]

4.19.3. The methods that will be used for determining continuous compliance, including a description of monitoring and reporting requirements; and [40 CFR § 63.9(h)(2)(i)(C)]

4.19.4. A statement by the permittee as to whether the source has complied with the relevant requirements. [40 CFR § 63.9(h)(2)(i)(G)]

4.20. NESHAP Change in Information Already Provided. Any change in the information already provided under a NESHAP standard shall be provided to the Administrator in writing within 15 calendar days after the change. [40 CFR § 63.9(j)]

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

5.1. At all times the permittee shall be in compliance with NESHAP Subpart ZZZZ requirements that apply to the permittee. [40 CFR § 63.6605(a)]

5.2. The permittee shall comply with the applicable NESHAP Subpart A general provisions listed in Table 8 to Subpart ZZZZ of Part 63, except that the requirement to submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) does not apply. [40 CFR §§ 63.6645(a)(5), 63.6665 and Table 8 to Subpart ZZZZ of Part 63]

Unit #5 Work Practice Requirements

5.3. The permittee shall change the oil and filter every 500 hours of operation or annually, whichever comes first. [40 CFR § 63.6602 and Row 6.a. of Table 2c to Subpart ZZZZ of Part 63]

5.3.1. The permittee has the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Condition 5.3 as follows:

5.3.1.1 The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content.

5.3.1.2 The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5.

5.3.1.3 If all these condemning limits are not exceeded, the engine owner or operator is not required to change the oil.

5.3.1.4 If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later.
[40 CFR § 63.6625(j) and footnote 2 of Table 2c to Subpart ZZZZ of Part 63]

5.4. The permittee shall inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.
[40 CFR § 63.6602 and Row 6.b. of Table 2c to Subpart ZZZZ of Part 63]

5.5. The permitee shall inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.
[40 CFR § 63.6602 and Row 6.c. of Table 2c to Subpart ZZZZ of Part 63]

5.6. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements pursuant to Conditions 5.3, 5.4 and 5.5, or if performing the management practice would otherwise pose an unacceptable risk under federal, state, or local law, the management practice shall be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. [Footnote 1 of Table 2c to Subpart ZZZZ of Part 63]

5.7. Except as provided for in Condition 5.8, the permittee may operate Unit #5 outside of emergency situations for up to 100 hours per calendar year and only for the following purposes:

5.7.1. Maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine;

5.7.2. Emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3;

5.7.3. For periods when there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency; and

5.7.4. Non-emergency situations up to 50 hours per calendar year. This 50-hour allowance cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[40 CFR § 63.6640(f)(1) through (3)]

5.8. The permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency engines beyond 100 hours per calendar year. [40 CFR § 63.6640(f)(2)(i)]

5.9. During periods of startup, the permittee shall minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

[40 CFR § 63.6625(h) and Table 2c to Subpart ZZZZ of Part 63]

5.10. At all times the permittee shall operate and maintain the engine, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emission does not require the permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[40 CFR § 63.6605(b)]

5.11. The permittee shall operate and maintain the engine and after-treatment control device (if any) according to the manufacturer's emission-related written operation and maintenance instruction, or alternatively, the permittee shall develop and follow its own maintenance plan which shall provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

[40 CFR §§ 63.6625(e), 63.6640(a) and Row 9 of Table 6 to Subpart ZZZZ of Part 63]

Unit #5 Monitoring and Recordkeeping Requirements

5.12. If the permittee utilizes an oil analysis program pursuant to Condition 5.3.1, the owner or operator shall keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program shall be part of the maintenance plan for the engine.

[40 CFR § 63.6625(j) and footnote 2 of Table 2c to Subpart ZZZZ of Part 63]

5.13. The permittee shall install a non-resettable hour meter if one is not already installed.

[40 CFR § 63.6625(f)]

5.13.1. The permittee shall keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter.

5.13.2. The permittee shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

5.13.3. If the engine is used for the purposes specified in Conditions 5.7.2 or 5.7.3, the permittee shall keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

[40 CFR § 63.6655(f)]

5.14. The permittee shall keep records to show continuous compliance with Condition 5.11.

[40 CFR § 63.6655(d)]

5.15. The permittee shall keep records of the maintenance conducted on the engine in order to demonstrate that the permittee operated and maintained the engine and after-treatment control device (if any) according to the permittee's own maintenance plan referred to in Condition 5.11. [40 CFR § 63.6655(e)]

Unit #5 Reporting Requirements

5.16. If Unit #5 operates or is obligated to be available for more than 15 hours per year for the purposes specified in Conditions 5.7.2 and 5.7.3, the permittee shall submit annual reports as follows:

5.16.1. The report shall contain the following information: (1) company name and address wheter the engine is located, (2) date of the report and beginning and ending dates of the reporting period, (3) engine site rating and model year, (4) latitude and longitude of the engine in decimal degrees reported to the fifth decimal place, (5) hours operated for the purposes specified in Conditions 5.7.2 and 5.7.3, and (6) number of hours the engine is contractually obligated to be available for the purposes specified in Conditions 5.7.2 and 5.7.3.

5.16.2. The first annual report shall cover the calendar year 2015 and shall be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

5.16.3. The annual report shall be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to EPA at the address specified in Condition 3.40.

[40 CFR § 63.6650(a), (h) and Row 4 of Table 7 to Subpart ZZZZ of Part 63]

5.17. The permittee shall report in the semi-annual monitoring report required by Condition 3.47 any failure to perform timely management practices as required by Conditions 5.3, 5.4 and 5.5 for reasons afforded by Condition 5.6. Report also the federal, state or local law under which the risk was deemed unacceptable.
[40 CFR §§ 71.6(a)(3)(iii)(A) and footnote 1 of Table 2c to Subpart ZZZZ of Part 63)]

5.18. The permittee shall report in the semi-annual monitoring report required by Condition 3.47 each instance in which the permittee did not meet the requirements in Table 8 to 40 CFR 63, Subpart ZZZZ. [40 CFR §§ 63.6640(e) and 71.6(a)(3)(iii)(A)]

5.19. The permittee shall report all deviations as defined in 40 CFR Part 63, Subpart ZZZZ in the semi-annual monitoring report required by Condition 3.47. [40 CFR § 63.6650(f)]

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

Units #6 and 7 Work Practice Requirements

6.1. Tune-ups. The permittee shall conduct tune-ups of Units #6 and 7 every 5 years.
[40 CFR §§ 63.7510(e) and 7500(a)(1)]

6.1.1. The initial tune-up shall be conducted no later than January 31, 2016. Subsequent tune-ups shall be conducted every 5-years to demonstrate continuous compliance. Each 5-year tune-up shall be no more than 61 months after the previous tune-up.
[40 CFR §§ 63.7495(b), 63.7500(a)(1), 63.7510(e), 63.7515(d), 63.7540 (12) and Item 1 in Table 3 to Subpart DDDDD]

6.1.2. For Unit #6 or 7 that has not operated between January 31, 2013, and January 31, 2016, the initial tune-up shall be conducted no later than 30 days after the re-start of that unit. For each unit that is not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, and for each unit not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup. [40 CFR §§ 63.7510(j), 63.7515(g) and 63.7540(a)(13)]

6.1.3. Tune-ups shall be conducted as follows:

6.1.3.1 As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled or unscheduled unit shutdown, but the permittee must inspect each burner at least once every 72 months). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

6.1.3.2 Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

6.1.3.3 Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown);

6.1.3.4 Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications; and

6.1.3.5 Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

[40 CFR §§ 63.7540(a)(10)(i) to (v) and 63.7540(a)(12)]

6.2. Energy Assessment. The permittee shall have a one-time energy assessment of Units #6 and 7 performed by a qualified energy assessor no later than January 31, 2016.

[40 CFR §§ 63.7495(b), 63.7500(a)(1), and 63.7510(e)]

6.2.1. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in Conditions 6.2.1.1 to 6.2.1.8, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for Conditions 6.2.1.1 through 6.2.1.5 appropriate for the on-site technical hours listed in 6.2.2:

6.2.1.1 A visual inspection of the boiler or process heater system.

6.2.1.2 An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.

6.2.1.3 An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.

6.2.1.4 A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.

6.2.1.5 A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.

6.2.1.6 A list of cost-effective energy conservation measures that are within the facility's control.

6.2.1.7 A list of the energy savings potential of the energy conservation measures identified.

6.2.1.8 A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

[40 CFR § 63.7500(a)(1) and Item 4.a. through h. in Table 3 to Subpart DDDDD]

6.2.2. The energy assessment will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. Each boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment. [40 CFR § 63.7575]

6.2.3. For each unit that has not operated between January 31, 2013, and January 31, 2016, the one-time energy assessment shall be conducted no later than 30 days after the re-start of that boiler. [40 CFR § 63.7510(j)]

6.3. Good Air Pollution Control Practices. At all times, the permittee shall operate and maintain the boilers, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR § 63.7500(a)(3)]

Units #6 and 7 Monitoring and Recordkeeping Requirements

6.4. Records. The permittee shall keep and maintain records as follows:

6.4.1. A copy of each notification and report submitted to comply with NESHAP Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status submitted according to the requirements in 63.10(b)(2)(xiv) (see Condition 4.19). . [40 CFR § 63.7555(a)(1)]

6.4.2. Records of the calendar date, time, occurrence and duration of each startup and shutdown. [40 CFR § 63.7555(i)]

6.4.3. Records of the type(s) and amount(s) of fuels used during each startup and shutdown. [40 CFR § 63.7555(j)]

6.4.4. On-site and submitted, if requested by the Administrator, an annual report containing the following:

6.4.4.1 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

6.4.4.2 A description of any corrective actions taken as a part of the tune-up.

[40 CFR § 63.7540(a)(10)(vi)]

6.4.5. Each record must be in a form suitable and readily available for expeditious review. Each record shall be kept for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Each record shall be kept on site, or they shall be accessible from onsite (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The permittee can keep the records off site for the remaining 3 years. [40 CFR §§ 63.7560(a) to (c)]

Units #6 and 7 Notification and Reporting Requirements

6.5. Notification of Compliance Status. The permittee shall submit all of the notifications in 40 CFR § 63.9(b) through (h) (see Condition 4.20) by the dates specified.
[40 CFR §§ 63.7495(d) and 63.7545(a)]

6.5.1. The notification shall include a description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit and a description of the fuel(s) burned. [40 CFR § 63.7545(e)(1)]

6.5.2. A signed certification that the permittee has met all applicable work practice standards. [40 CFR § 63.7545(e)(6)]

6.5.3. If the permittee has a deviation from any work practice standard, the permittee must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report. [40 CFR § 63.7545(e)(7)]

6.5.4. In addition to the information required in §63.9(h)(2) (see Condition 4.20), the notification shall include the following certification(s) of compliance, as applicable, and be signed by a responsible official:

6.5.4.1 "This facility complies with the required initial tune-up according to the procedures in §63.7540(a)(10)(i) through (vi) (see Condition 6.1)"

6.5.4.2 "This facility has had an energy assessment performed according to § 63.7530(e) (see Condition 6.2)."
[40 CFR §§ 63.7530(d) and (e) and 63.7545(e)(8)]

6.6. Annual Compliance Reports. The permittee shall submit 5-year compliance reports.
[40 CFR § 63.7550(a) and Item 1.a in Table 9 to Subpart DDDDD]

6.6.1. The first compliance report shall cover the period beginning on January 31, 2016, and ending on January 31, 2017, and be postmarked and submitted no later than January 31, 2017. [40 CFR § 63.7550(b)(1) and (2)]

6.6.2. Each subsequent compliance report shall cover the 5-year reporting period from January 1 to December 31, and be postmarked or submitted no later than January 31.
[40 CFR § 63.7550(b)(3) and (4)]

6.6.3. The compliance report shall include the following information: [40 CFR § 63.7550(c)(1)]

6.6.3.1 Company and Facility name and address. [40 CFR § 63.7550(c)(5)(i)]

6.6.3.2 Process unit information. [40 CFR § 63.7550(c)(5)(ii)]

6.6.3.3 Date of report and beginning and ending dates of the reporting period.
[40 CFR § 63.7550(c)(5)(iii)]

6.6.3.4 The total operating time during the reporting period.
[40 CFR § 63.7550(c)(5)(iv)]

6.6.3.5 The date of the most recent tune-up for each unit subject to only the requirement to conduct an 5-year tune-up according to §63.7540(a)(12) (see Conditions 6.1.3 and 6.4.4), and the date of the most recent burner inspection if it was not done on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. [40 CFR § 63.7550(c)(5)(xiv)]

6.6.3.6 If there are no deviations from the requirements for work practice standards in Table 3 to Subpart DDDDD of Part 63 that apply to the permittee, a statement that there were no deviations from the work practice standards during the reporting period. [Item 1.b in Table 9 to Subpart DDDDD]

6.6.3.7 If the permittee has a deviation from a work practice standard during the reporting period, the report must contain a description of the deviation and information on the duration and cause of the deviation and corrective action taken.
[Item 1.c in Table 9 to Subpart DDDDD and 40 CFR §§ 63.7550(d)(1) and (2)]

6.6.3.8 A statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. [40 CFR § 63.7550(c)(5)(xvii)]

6.6.4. All reports shall be submitted electronically using the Compliance and Emissions Data Reporting Interface that is accessed through the EPA's Central Data Exchange (www.epa.gov/cdx). If the reporting form specific to this subpart is not available in

CEDRI at the time that the report is due, the report shall be submitted to the address listed in Condition 3.40. [40 CFR § 63.7550(h)]

6.7. Notification of Fuel Switch or Physical Change. The permittee shall provide notice to the EPA within 30 days of the switch/change if the permittee has switched fuels or made a physical change to a boiler and the fuel switch or physical change resulted in the applicability of a different subcategory of NESHAP Subpart DDDDD. The notice shall identify:

6.7.1. The name of the owner or operator of the boiler, the location of the boiler, identification of the boiler that has switched fuels or was physically changed, and the date of the notice.

6.7.2. The currently applicable subcategory under NESHAP Subpart DDDDD.

6.7.3. The date upon which the fuel switch or physical change occurred.

[40 CFR § 63.7545(h)]

7. Abbreviations and Acronyms

§	Section
Btu	British thermal units
CAA	Clean Air Act [42 U.S.C. section 7401 et seq.]
CFR	Code of Federal Regulations
dscf	Dry standard cubic feet
EPA	United States Environmental Protection Agency (also U.S. EPA)
EU	Emission Unit
FARR	Federal Air Rules for Reservations
gr	grains (7,000 grains = 1 pound)
hr	Hour
lb	Pound (lbs = pounds)
MACT	Maximum Achievable Control Technology
NESHAP	National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)
NO_x	Nitrogen oxides
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
ppmdv	Parts per million on a dry, volume basis
PSD	Prevention of significant deterioration
PTE	Potential to emit
S	Sulfur
SO_2	Sulfur dioxide
VOC	Volatile organic compound

United States Environmental Protection Agency
Region 10, Office of Air, Waste and Toxics
AWT-150
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101-3140

Permit Number: R10T5110100
Issued: September 30, 2015
Effective: October 31, 2015
Expiration: September 30, 2020
Replaces: R10T5-ID-02-01
AFS Plant I.D. Number: 16-005-00049

Statement of Basis

Title V Air Quality Operating Permit
Permit Renewal #1

Permit Writer: Dan Meyer

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.

Table of Contents

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.

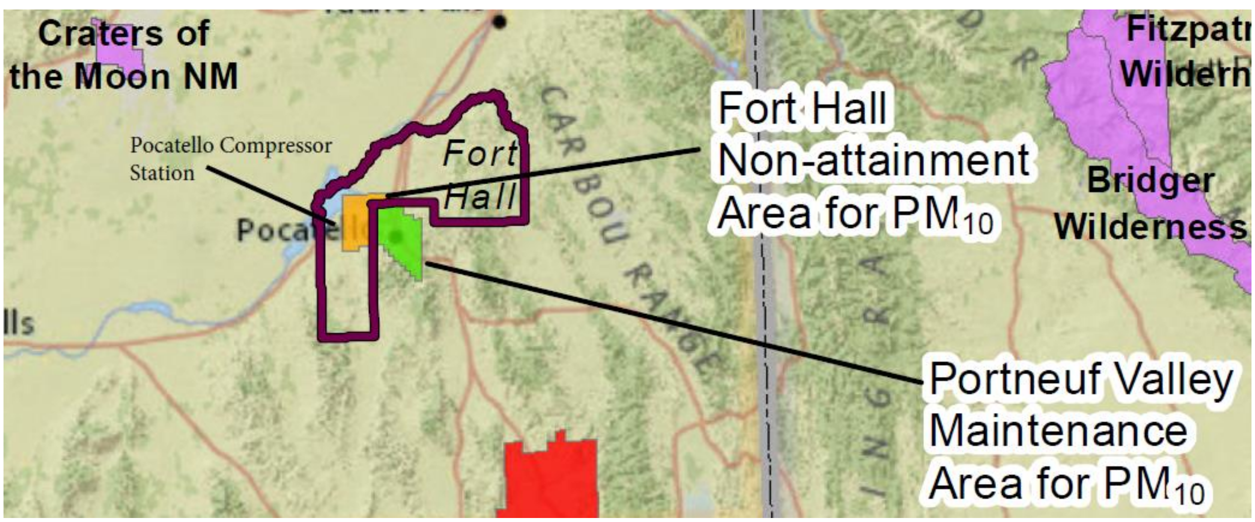
As described in 40 CFR 71.4(a), EPA will implement a Part 71 program in areas where a state, local, or Tribal agency has not developed an approved Part 70 program. Unlike states, Indian Tribes are not required to develop operating permit programs, though EPA encourages Tribes to do so. See, for example, Indian Tribes: Air Quality Planning and Management (63 FR 7253, February 12, 1998) (also known as the “Tribal Authority Rule”). Therefore, within Indian Country, EPA will administer and enforce a Part 71 federal operating permit program for stationary sources until the governing Indian Tribe receives EPA’s approval to administer its own operating permit program.

2. Facility Information

2.1 Location

The Northwest Pipeline (NWP) 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 and a delineation of the nearby Fort Hall PM_{10} non-attainment area and Portneuf Valley PM_{10} maintenance area (further to the east) is shown in Figure 2-1.

Figure 2-1 – Facility Location



Map produced by Idaho Department of Environmental Quality and made available at http://www.deq.idaho.gov/media/662796-nonattainment_map.pdf

2.2 Fort Hall Indian Reservation

The NWP 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 NWP Pocatello Compressor Station relative to its position within the Fort Hall Reservation.

Tribal Contact: Penny Weymiller
Air Quality Program Manager
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P.O. Box 306
Fort Hall, Idaho 83203
Phone: (208) 478-3853
Email: pweymiller@sbtribes.com

2.3 Local Air Quality and Attainment Status

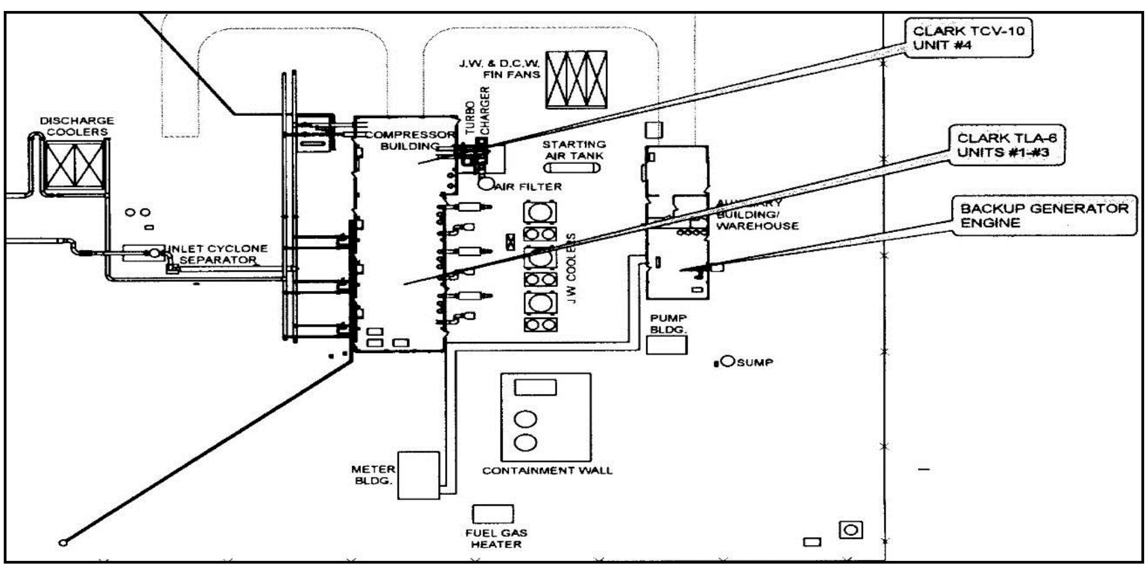
The Fort Hall Indian Reservation and surrounding area is in attainment with all national ambient air quality standards, or is unclassifiable, with the exception of PM_{10}. As designated under 40 CFR § 81.313 a PM_{10} nonattainment area lies within a portion of the Fort Hall Indian Reservation. The 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).

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 (MNA) consist of leaks from the piping valves, flanges, and open-ended lines, and compressors associated with the source.	None
Unit 11*	Used Lube Oil Tank, 2,940 gallons (70 BBL); Used Lube Oil Tank 2,940 gallons (70 BBL); (2) Scrubber Oil Tanks 310 gallons per tank (7.4 BBL) - Scrubber tanks store 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 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 several emission units as IEUs in their Title V application: one boiler, one fuel heater, miscellaneous non-fugitive activities (i.e., several space heaters and furnaces), system blowdown gas, miscellaneous fugitive activities (i.e., leaks from piping) and four oil storage tanks. 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. The permit includes National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart DDDDD requirements specific to the boiler and fuel heater. Because all of the insignificant emission units qualify by meeting the insignificant emission unit 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 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.

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]	Four Natural Gas Compressor RICE	Backup Generator RICE	Boiler & Heater	Heaters & Furnaces	System Blowdown	Equipment Leaks & Oil Storage Tanks	Total
CO	100.2	3.5	1.4	0.4			106
Pb							0
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; Pb = lead; 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.

4. Regulatory Analysis and Permit Content

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.

The Pocatello Compressor Station is located within Indian Country and is subject to federal air quality regulations. It is not, however, subject to state air quality regulations. The facility could also 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 Clean Air Act and the implementing regulation found in 40 CFR part 71 require major sources (as well as a selection of 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 Title V pollutant, 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 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 EPA believes it is necessary, as explained in Section 4.3 (Permit Conditions) of this Statement of Basis below.

Compliance Assurance Monitoring (CAM) – CAM applies to emission units that are subject to an emission limit with a pre-control potential to emit emissions equal to or greater than the major source threshold defined in Title V (generally, 100 tons per year) and that use a control device to comply with the limit (see 40 CFR Part 64). All units that meet the CAM applicability criteria must be in compliance with CAM at permit renewal and may also be required to submit a CAM plan if a significant change is made to the unit prior to renewal. Each of the four compressor engines at the Pocatello Compressor Station has a PTE for NOx greater than 100 tons per year. However, because none of the engines are equipped with a control device, CAM does not apply.

Prevention of Significant Deterioration (PSD) – Under the PSD pre-construction permitting program found in Part C of the Clean Air Act and 40 CFR 52.21, no “major stationary source” or “major modification” to a major stationary source can begin actual construction without first obtaining a PSD permit. In general, a major stationary source for purposes of the PSD program is a source with a PTE of more than 250 tons per year of any PSD pollutant. A modification is major if it results in emission increases greater than defined significance levels.

The four main gas compressor engines (Emission Units 1, 2, 3 and 4) were installed before PSD requirements existed. Their PTE is greater than 250 tons per year of NO_X. 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. 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. Any future modifications that result in a significant emission increase will be subject to PSD.

EPA is not aware of any other modifications to the facility and does not draw any conclusions regarding compliance with past permitting requirements for this facility. Therefore, no permit shield is implied or explicit for past new source review or PSD requirements.

New Source Performance Standards (NSPS) – There are no applicable NSPS regulations 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.

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.

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 40 CFR NSPS Subpart JJJJ [§60.4230(a)(4)].

National Emission Standards for Hazardous Air Pollutants (NESHAP) – With a few exceptions, MACT 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 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.

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

National Emission Standard for Hazardous Air Pollutant (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 hazardous air pollutant service, therefore, Subpart HH does not apply.

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

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 [§63.1270(a) (b)& (c)].

There are two MACT standards that are applicable to this facility: Subpart ZZZZ (Stationary Reciprocating Internal Combustion Engines (RICE)) and Subparts 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).

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), 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, or the initial notification requirements of 40 CFR 63.6590(b)(3)(i). Table 4-1 below summaries MACT ZZZZ applicability.

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

EU I.D. #	Description	Capacity	Subpart ZZZZ Applicable?
1, 2 and 3	Clark TLA-6 Gas Compressor Engine; Two-stroke, lean-burn; Installed 1956	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	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	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 § 63.6585(f). Under § 63.6585(f), an emergency stationary RICE must meet the definition of such a RICE under § 63.6675, which includes operating according to the provisions specified in §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 MACT regulations.

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

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) – In early 2005, EPA promulgated a Federal Implementation Plan (FIP) for Reservations in Idaho, Oregon and Washington. This FIP is commonly referred to as the Federal Air Rules for Reservations (FARR). The FARR provisions that apply on the Fort Hall Reservation are codified at 40 CFR § 49.10706. The provisions of the FARR that apply to the permittee and have been included in the permit are discussed in Section 4.3 below.

Acid Rain – 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 power. The facility's boiler is not an "affected unit" as defined in 40 CFR 72.6 because it satisfies none of the criteria for applicability.

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 40 CFR 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

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 Office of Air, Waste and Toxics has contacted the Tribes to invite consultation on the NW Pipeline 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 Clean Air Act 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 Clean Air Act 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.

4.3 Permit Conditions

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 needed so the permit assures compliance with all of the applicable requirements. Each permit condition in the permit is explained below. The permit is organized into the following six sections:

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 – Unit #5 (Emergency Backup Generator)
Permit Section 6:	Unit-Specific Requirements – Units #6 and 7 (Boiler and Fuel Gas heater)

Permit Section 1 – Source Information

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.

Permit Section 2 – Standard Terms and Conditions

This permit section includes generic compliance terms that are required in all Title V permits, but are not subject to the annual compliance certification requirements found in Permit Condition 3.49.

In this proposed renewal of an existing part 71 permit, the EPA is not including the "Emergency Provisions" provision as they appeared in the existing permit located in permit condition VI.C in the existing part 71 permit. These provisions were modeled on the "Emergency provision" contained in the regulations contained in 40 CFR part 71 applicable to federal operating permit programs. Specifically, in the regulations discussing the contents of title V operating permits issued under the federal operating permits program, 40 CFR 71.6(g) provides that certain "emergency" events that can constitute "an affirmative defense in an action brought for non-compliance" with certain emission limits contains in the permit, when certain conditions are met. However, nothing in the CAA or 40 CFR part 71 requires that these types of emergency provisions be included as conditions in operating permits issued by the EPA, and for the reasons discussed below, we are exercising our discretion not to include them in this proposed renewal part 71 permit.

In 2014, a federal court ruled that the CAA does not authorize the EPA to create affirmative defense provisions applicable to certain enforcement actions. *See NRDC v. EPA*, 749 F.3d 1055 (D.C. Cir. 2014). The court ruled that Sections 113 and 304 of the Clean Air Act preclude the EPA from creating affirmative defense provisions in the Agency's regulations imposing hazardous air pollutants emission limits on sources. The court concluded that those affirmative defense provisions purported to alter the jurisdiction of federal courts generally provided in the CAA to assess liability and impose penalties for violations of emission limits in private civil enforcement cases, and that the CAA did not provide authority for the EPA to do so. Consistent with the reasoning in the *NRDC v. EPA* court decision, EPA has determined that is also not appropriate under the CAA to alter the jurisdiction of the federal courts through affirmative defenses provisions in its title V regulations, such as those contained in the emergency provisions of 40 CFR 71.6(g), and that such provisions are inconsistent with the CAA. In light of the above-described D.C. Circuit Court decision and the EPA's obligation to issue title V permits consistent with the applicable requirements of the Act, it is no longer appropriate to include permit conditions modeled on affirmative defenses such as those contained in the emergency provisions of 40 CFR 71.6(g) in operating permits issued by the EPA.

Although the EPA views the Part 71 emergency provisions as discretionary (i.e., neither the statute nor the regulations mandate their inclusion in Part 71 permits), the EPA is considering whether to make changes to the operating permit program regulations in order to ensure the EPA's regulations are consistent with the recent D.C. Circuit decisions; and if so, how best to make those changes. Until that time, as part of the normal permitting process, it is appropriate for the EPA permitting authorities to rely on the discretionary nature of the existing emergency provisions to choose not to continue to include permit terms modeled on those provisions in operating permits that we are issuing in the first instance or renewing. By doing so, we are not only fulfilling the EPA's obligation to issue title V permits consistent with the applicable requirements of the Act, but we will also help ensure that permitees do not continue to rely on permit provisions that have been found legally invalid. Accordingly, in this proposed renewal part 71 permit, the EPA is exercising its discretion to not include the "Emergency Provisions" provision as they appeared in the existing permit located in permit condition VI.C in the existing part 71 permit, in order to ensure the Part 71 permit is in compliance with the applicable requirements of the Act.

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 should be used to interpret and implement the requirement. This permit condition also notes some underlying authorities that may have been used to create additional requirements in this permit.

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 other than for major source MACT requirements as discussed in Section 4.1 in this Statement of Basis.

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 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 will be 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 the EPA is not aware of any non-compliance at the time of permit issuance, there is no issue-specific compliance schedule in Section 4 of 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 wherever the FARR applies including at industrial facilities. If the permittee performs any open burning, recordkeeping requirements specific to open burning found in Permit Condition 3.33 will apply.

Permit Condition 3.9 through 3.11 limit visible emissions, require the use of either Reference Method 9 or a continuous opacity monitoring system for determining compliance with the limit, and provide exception to the rule. 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. This requirement is included in the permit as an applicable requirement because the facility is subject to Part 68 based on the quantity of oil stored onsite.

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 should be followed. 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 describes 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 should be followed.

Permit Conditions 3.36 and 3.37 require the permittee to submit or correct submitted information when requested by the 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 the EPA of any errors or omissions.

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), should be sent to this address. Copies of each document sent to Region 10 that does not contain certain confidential business information shall be 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; the permittee should contact the 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 the 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, the emission estimation techniques listed in this statement of basis should 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 emissions 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. At this time, greenhouse gases are neither regulated air pollutants nor regulated air pollutant (for fee calculation) as those terms are defined at 40 CFR § 71.2. The permittee is not required to pay Title V fees on its GHG emissions.

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 the 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, the emission estimation techniques listed in this statement of basis should 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 emissions 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 the 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 6. 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 that permit was in effect. Forms for the annual compliance certifications may be obtained on the internet at http://www.epa.gov/air/oaqps/permits/p71forms.html.

Permit Condition 3.50 requires the permittee to certify the truth, accuracy and completeness of all documents (notices, reports, data, and etc) submitted to Region 10. The certification must be signed by a responsible official as defined in 40 CFR § 71.2. The facility's responsible official is listed on the first page of the permit. The permittee should 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.

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 and 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:

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

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

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

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 = $385x10^6$ 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 = $1x10^6$ 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:

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

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

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

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.

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 term 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 4.20 are generally applicable requirements that apply to Northwest Pipeline – Pocatello Compressor Station's emergency backup RICE (Unit #5) and the boiler and fuel gas heater (Units #6 and 7). Condition 4.19 does not apply to Unit #5 because the NESHAP Subpart ZZZZ compliance date has already passed.

Permit Section 5 – Unit-Specific Requirements – 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. Compliance with MACT ZZZZ requirements must be achieved no later than May 3, 2013 pursuant to 40 CFR § 63.6595(a)(1).

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 – Unit #6 (Boiler) and 7 (Process Heater)

Permit Condition 6.1 requires annual tune-ups of the Units #6 and 7 with the first one due by January 31, 2016, and specifies what must be included in the tune-ups.

Permit Condition 6.2 requires one energy assessment of Units #6 and 7 by January 31, 2016, and specifies what must be addressed in the assessment.

Permit Condition 6.3 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 6.4 specifies the records that must be maintained consistent with Condition 4.18. Conditions 6.4 and 4.18 should be read together. Condition 6.4.5 clarifies that records only have to be kept onsite for the first two of the required five years.

Permit Condition 6.5 requires a notification of compliance status as specified in Condition 4.19 regarding the tune-ups and energy assessment required in Condition 6.1 and 6.2. These two requirements should be read together.

Permit Condition 6.6 requires annual compliance reports and describes the contents of the reports and technique for submittal.

Permit Condition 6.7 requires notification when switching fuels.

5. Public Participation

5.1 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 have been satisfied as follows:

1. Publishing the public notice for this draft permit in a daily or weekly newspaper of general circulation in the area affected by this source. In this case, publication was provided in the daily Idaho State Journal on Saturday August 29, 2015.
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 Region 10's mailing list for Title V permitting actions;
3. Making available from August 28, 2015 through date of permit issuance on the Region 10 public notice website [http://yosemite.epa.gov/R10/homepage.nsf/Information/R10PN/] during the public comment period, a copy of the public notice and the draft permit and statement of basis prepared by Region 10;
4. Making available from August 29, 2015 through September 28, 2015 at the locations listed below, a copy of the public notice, draft permit, the statement of basis, the application, and relevant supporting materials:

Shoshone-Bannock Library Tribal Business Center Fort Hall, ID 83203 (208) 478-3882	U.S. EPA, Region 10 Public Library 1200 Sixth Avenue Seattle, WA (206) 553-1289

5.2 Response to Public Comments and Permit Issuance

The public comment period for this permit ran from August 29, 2015 to September 28, 2015. EPA received comments from Northwest Pipeline's Derek Forsberg. As required in 40 CFR § 71.11(e), EPA has considered the comments and has developed a response to each. The comments are presented below just as they were received along with a response that explains whether any change to the permit resulted and the reason why a change was or was not made. There was no public hearing requested or held. As required in 40 CFR § 71.11(i), EPA will notify the applicant and each person who has submitted comments or requested notice of the final permit decision.

Comments from Northwest Pipeline's Derek Forsberg Submitted September 28, 2015:

1. *Today, the name of the company is Williams Northwest Pipeline LLC. However, it also was announced today the Energy Transfer Equity has purchased Williams so the name may be changing again.*

> EPA Response: If there exists a written agreement between Northwest Pipeline and Energy Transfer Equity containing a specific date for transfer of permit responsibility, coverage, and liability, please share that agreement with EPA in support of an administrative amendment to the permit changing the name of the permittee pursuant to 40 CFR § 71.7(d)(1)(iv).

2. *The station address is 2605 Gas Plant Road not 2615 Gas Plant Road.*

> EPA Response: Page 1 of the permit has been amended to address the error highlighted by this comment.

3. *Table 1 (Unit 11) The Scrubber Oil tanks are 310 gallons each not 310 BBLs each.*

> EPA Response: Table 1 of the permit and Table 2-1 of the SoB have been amended to address the error highlighted by this comment.

4. *Section 3.9. Northwest would like the opportunity to negotiate alternatives to the Methods outlined in the draft permit. Method 9 should be removed as a requirement. The facility only burns natural gas and opacity has never been an issue at the station. Northwest should not be required to perform a Method 9 test. The station only burns natural gas and therefore will never have an opacity issue. If there is black smoke coming from an engine, that means the engine is on fire and the unit will be shut down immediately. The engines have never caught fire since being installed in 1956 and therefore there has never been an issue with opacity.*

> EPA Response: Condition 3.9 of the permit states the applicable six-minute 20 percent opacity visible emissions limit and the accompanying methods for measuring opacity to determine compliance. The visible emissions limit and prescribed methods for measuring compliance are a part of the Federal Air Rules for Reservations (FARR) established through rulemaking in the Federal Register on April 8, 2005. See 40 CFR § 49.124(d)(1) and (e) for the specific provisions from which EPA drew to create Condition 3.9. Because EPA does not have the authority in a Title V permit to amend the underlying emission limit and compliance method presented in Condition 3.9, EPA is not providing Northwest Pipeline an opportunity to negotiate Condition 3.9.
>
> The commenter states that Northwest Pipeline should not be required to perform a Method 9 test. Condition 3.9 does not actually require the permittee to conduct EPA Reference Method 9. As stated previously, Condition 3.9 simply states the visible emissions limit and prescribed methods for measuring compliance.

5. *Section 4.3 and 4.4 Northwest would like to comply with the fuel sulfur requirements by having sulfur limit language in the Northwest natural gas tariff agreement. The Pocatello permit should state that Northwest will comply with the sulfur requirements by demonstrating a natural gas tariff with outlined fuel sulfur limits. Northwest proposes this language:*

> *Compliance with the sulfur content limit will be demonstrated through the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content is 20 grains of sulfur or less per 100 standard cubic feet.*
>
> EPA Response: Condition 4.4 has been amended to specify the type of records permittee is to keep, showing that the gaseous fuel meets the definition of natural gas in 40 CFR § 72.2. The definition of natural gas in 40 CFR § 72.2 states, "natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet." This maximum concentration is equivalent to 0.5 grams per dry standard cubic meter, less than one-half the applicable FARR limit of 1.1 grams per dry standard cubic meter specified in Condition 4.3.[1]
>
> The records EPA is requiring the permittee to keep shall consist of a current, valid purchase contract, tariff sheet or transportation contract for the fuel. This means that at any given time, the permittee is required to show evidence of a current binding agreement specifying that the natural gas passing through the facility must have a sulfur content less than one-half the limit specified in

[1] $0.5 \text{ g/m}^3 = (20 \text{ gr}/100 \text{ ft}^3) \times (0.0648 \text{ g/gr}) \times (100 \text{ ft}^3/2.8317 \text{ m}^3)$

Condition 4.3. We are prescribing this recordkeeping under authority of 40 CFR §§ 71.6(a)(3)(i)(B) and 71.6(c), and the recordkeeping is sufficient to assure compliance with the sulfur content limit specified in Condition 4.3.

6. *Section 4.5 and 4.6 Emission testing is not required so these sections should be removed.*

EPA Response: Although the permittee is not required to conduct emissions testing of any combustion unit to determine compliance with Conditions 4.5 and 4.6, that is not a basis to remove the underlying applicable emission limits from the permit. The limits still apply, and your Title V permit is required to contain all applicable requirements.

7. *Section 4.7 through 4.13 Northwest would like the opportunity to negotiate alternatives to the Methods outlined in the draft permit. Method 9 should be removed. The facility only burns natural gas and opacity has never been an issue at the station. See comment for Section 3.9.*

EPA Response: Conditions 4.7 through 4.13 require the permittee to conduct quarterly visible emissions surveys of the facility. As we stated previously in § 4.3 of this SoB:

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.

To get a sense for whether the periodic monitoring that we are prescribing is reasonable and appropriate, EPA conducted a cursory review of eight Title V permits issued by other permit authorities for other compressor stations in Idaho and Washington.[2] Each of the eight Title V permits require quarterly visible emissions surveys, and each of the permits require the permittee to conduct EPA Reference Method 9 observations in the event visible emissions observed during the survey have not been eliminated within 24 hours or three days (depending upon the permit authority) of discovery. Given that other permit authorities have created requirements similar to Conditions 4.7 through 4.13 for other compressor stations located in the same area of the country, EPA is not inclined to amend the permit in response to this comment.

6. Abbreviations and Acronyms

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
COM	Continuous opacity monitor
dscf	Dry standard cubic feet (stand conditions for natural gas is
EU	Emission Unit
EPA	United States Environmental Protection Agency (also U.S. EPA)
FARR	Federal Air Rules for Reservations
FR	Federal Register
gr/dscf	Grains per dry standard cubic foot (7,000 grains = 1 pound)

[2] EPA reviewed six Title V permits issued to Northwest Pipeline by Idaho Department of Environmental Quality and two Title V permits issued to Transmission Northwest by State of Washington Department of Ecology Eastern Regional Office for natural gas pipeline compressor stations at the following locations: Boise (ID), Caldwell (ID), Lava Hot Springs (ID), Mountain Home (ID), Pegram (ID), Soda Springs (ID), Starbuck (WA) and Wallula (WA).

HAP	Hazardous air pollutant
IEU	Insignificant emission unit
IC	Internal combustion
hr	Hour
lb	Pound
MACT	Maximum Achievable Control Technology
MM	One million
NESHAP	National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)
NO_X	Nitrogen oxides
NWP	Northwest Pipeline
PM	Particulate matter
PM_{10}	Particulate matter less than or equal to 10 microns in aerodynamic diameter
ppm	Parts per million
PSD	Prevention of significant deterioration
PTE	Potential to emit (based on 8,760 hours of operation per year)
RICE	Reciprocating Internal Combustion Engines
scf	Standard cubic feet (for natural gas is at 1 atmosphere pressure and 60 degrees F)
SO_2	Sulfur dioxide
tpy	Tons per year
VOC	Volatile organic compound

Appendix A

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

Statement of Basis

Title V Air Quality Operating Permit Renewal #1

R10T5110100

Pocatello, Idaho

Appendix A: Potential Emissions Inventory

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.
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 $CF_{7\rightarrow 0\%O2}$ X F_d (dscf/MMBtu) / $CF_{gr\rightarrow lb}$ (gr/lb) • $CF_{7\rightarrow 0\%O2}$ = (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)	$CF_{7\rightarrow 0\%O2}$ (unitless)	F_d (dscf/MMBtu)	$CF_{gr\rightarrow lb}$ (gr/lb)
0.1871	0.1	1.504	8,710	7,000

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 $CF_{7\rightarrow 0\%O2}$ X $CF_{ppm\rightarrow lb/dscfSO2}$ X F_d (dscf/MMBtu)

• $CF_{7\rightarrow 0\%O2}$ = (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)	$CF_{7\rightarrow 0\%O2}$ (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 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-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			All Three Engines
	EF ($lb/1x10^6$ scf)	EF (lb/MMBtu)	PTE (tpy)	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,I)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	

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.

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

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

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-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 $CF_{7\to0\%O2}$ X F_d (dscf/MMBtu) / $CF_{gr\to lb}$ (gr/lb)

• $CF_{7\to0\%O2}$ = (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)	$CF_{7\to0\%O2}$ (unitless)	F_d (dscf/MMBtu)	$CF_{gr\to lb}$ (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) / $CF_{100ft3\to Btu}$ X $CF_{Btu\to MMBtu}$ / $CF_{gr\to lb}$ X $CF_{S\to SO2}$

• $CF_{S\to SO2}$ = 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.

• $CF_{ft3\to Btu}$ = 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)	$CF_{ft3\to Btu}$ (Btu/100 ft^3)	$CF_{Btu\to MMBtu}$ (Btu/MMBtu)	$CF_{gr\to lb}$ (gr/lb)	$CF_{S\to SO2}$ (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) / $CF_{m3\to ft3}$ / $CF_{ft3\to Btu}$ X $CF_{Btu\to MMBtu}$ / $CF_{g\to lb}$ X $CF_{S\to SO2}$

• $CF_{S\to SO2}$ = 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.

• $CF_{ft3\to Btu}$ = 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)	$CF_{m3\to ft3}$ (ft^3/m^3)	$CF_{ft3\to Btu}$ (Btu/ft^3)	$CF_{Btu\to MMBtu}$ (Btu/MMBtu)	$CF_{g\to lb}$ (g/lb)	$CF_{S\to SO2}$ (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 $CF_{7\to0\%O2}$ X $CF_{ppm\to lb/dscfSO2}$ X F_d (dscf/MMBtu)

• $CF_{7\to0\%O2}$ = (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.

• $CF_{ppm\to lb/dscfSO2}$ = 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)	$CF_{7\to0\%O2}$ (unitless)	$CF_{ppm\to lb/dscfSO2}$ (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 $CF_{kg\to lb}$ (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)	$CF_{kg\to lb}$ (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 $CF_{kg\to lb}$ (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)	$CF_{kg\to lb}$ (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 $CF_{kg\to lb}$ (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)	$CF_{kg\to lb}$ (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: ?
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 $CF_{7\rightarrow 0\%O2}$ X F_d (dscf/MMBtu) / $CF_{gr\rightarrow lb}$ (gr/lb)
• $CF_{7\rightarrow 0\%O2}$ = (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>$CF_{7\rightarrow 0\%O2}$ (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 $CF_{7\rightarrow 0\%O2}$ X $CF_{ppm\rightarrow lb/dscfSO2}$ X F_d (dscf/MMBtu)
• $CF_{7\rightarrow 0\%O2}$ = (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>$CF_{7\rightarrow 0\%O2}$ (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: ?
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 or
** 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	

<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)
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• $CF_{7\rightarrow0\%O2}$ = (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 + $O_2 \rightarrow SO_2$. 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>
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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 + $O_2 \rightarrow SO_2$. 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-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 or

** 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.

<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 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

<table>
<tr><th>EF Reference</th><th>Description</th></tr>
<tr><td>1</td><td>EF (lb Hexane/$1x10^6$ scf) = (MW_{gas}) X (wt. % Hexane/100) / ($Density_{gas}$) X $CF_{100scf \rightarrow MMscf}$
Values for variables provided by applicant.
<table>
<tr><td>Hexane EF for CH_4 ($lb/1x10^6$ scf)</td><td>MW_{gas} (lb/lb-mol)</td><td>wt. % VOC/100 (unitless)</td><td>$Density_{gas}$ (scf/lb mol)</td><td>$CF_{scf \rightarrow MMscf}$ ($scf/1x10^6$ scf)</td></tr>
<tr><td>3.19E+01</td><td>19.25</td><td>0.000628</td><td>379</td><td>1.0E+06</td></tr>
</table></td></tr>
<tr><td>2</td><td>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 $CF_{100scf \rightarrow MMscf}$ / $CF_{gr \rightarrow lb}$ X $CF_{S \rightarrow H2S}$
• $CF_{S \rightarrow H2S}$ = 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.
<table>
<tr><td>Pipeline Tariff Calculate H_2S EF ($lb/1x10^6$ scf)</td><td>Pipeline Tariff Fuel Sulfur Limit (gr/100 ft^3)</td><td>$CF_{100scf \rightarrow MMscf}$ ($100 scf/1x10^6$ scf)</td><td>$CF_{gr \rightarrow lb}$ (gr/lb)</td><td>$CF_{S \rightarrow H2S}$ (lb H_2S/lb S)</td></tr>
<tr><td>3.21E+01</td><td>20</td><td>10000</td><td>7000</td><td>1.125</td></tr>
</table></td></tr>
<tr><td>3</td><td>Table 1.4-2 of AP-42, July 1998. Lead is a "pass through" pollutant.</td></tr>
<tr><td>4</td><td>EF (lb VOC/$1x10^6$ scf) = (MW_{gas}) X (wt. % VOC/100) / ($Density_{gas}$) X $CF_{100scf \rightarrow MMscf}$
Values for variables provided by applicant.
<table>
<tr><td>VOC EF for CH_4 ($lb/1x10^6$ scf)</td><td>MW_{gas} (lb/lb-mol)</td><td>wt. % VOC/100 (unitless)</td><td>$Density_{gas}$ (scf/lb mol)</td><td>$CF_{scf \rightarrow MMscf}$ ($scf/1x10^6$ scf)</td></tr>
<tr><td>1.02E+03</td><td>19.25</td><td>0.019993</td><td>379</td><td>1.0E+06</td></tr>
</table></td></tr>
<tr><td>5</td><td>EF (lb $CO_2e/1x10^6$ scf) = (MW_{gas}) X (wt. % CH_4/100) / ($Density_{gas}$) X $CF_{100scf \rightarrow MMscf}$ X GWP_{CH4} (lb CO_2e/lb CH_4)
Estimate that wt. % CH_4 in natural gas is 80%.
<table>
<tr><td>CO_2e EF for CH_4 (lb $CO_2e/1x10^6$ scf)</td><td>MW_{gas} (lb/lb-mol)</td><td>wt. % CH_4/100 (unitless)</td><td>$Density_{gas}$ (scf/lb mol)</td><td>$CF_{scf \rightarrow MMscf}$ ($scf/1x10^6$ scf)</td><td>40 CFR 98 Table A-1 GWP_{CO2} (lb CO_2e/lb CH_4)</td></tr>
<tr><td>1.02E+06</td><td>19.25</td><td>0.8</td><td>379</td><td>1.0E+06</td><td>25</td></tr>
</table></td></tr>
</table>

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

Appendix A: Potential Emissions Inventory

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.